Carbon Pricing in Illinois

Prepared by Harris Policy Labs at the University of Chicago for the Illinois Commerce Commission

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1. INTRODUCTION

Over the years, Illinois has adopted multiple policies to address carbon dioxide emissions and other pollutants from the state's electricity sector. The state is home to various renewable energy and energy efficiency programs, which incorporate goals to advance renewable resources (e.g., wind and solar) and reduce electricity use over time. While these policies and programs are becoming increasingly more common amongst states, they do not represent the full collection of policy options intended to address greenhouse gas (GHG) emissions in the electricity sector.

One specific policy tool that is less widespread, but has been adopted and implemented by California and 11 states in the Northeast region of the United States, is a carbon pricing mechanism. This policy approach is one option for states to consider as they look to reduce carbon emissions. As such, the purpose of this report is to identify how the State of Illinois can price carbon in the electricity sector, consistent with state and federal energy policies and objectives.

The report uses the 11-state Regional Greenhouse Gas Initiative (RGGI) carbon pricing framework states as a starting point for assessing different potential pricing mechanisms and their potential impacts within the market of a single regional transmission organization (RTO), PJM. The reasons for focusing on RGGI are because multiple PJM states are already RGGI members, RGGI is likely to be a relatively straightforward approach for Illinois to implement carbon pricing compared with designing a program from scratch, and the impacts to states and wholesale electricity markets have already been modeled and analyzed by PJM and other stakeholders. The reasons for focusing on PJM are because a majority of Illinois' wholesale electricity sales occur within PJM's market and PJM has demonstrated a willingness to explore state carbon pricing mechanisms. Thus, this report analyzes potential membership in RGGI from Illinois' perspective, but within the context of PJM.

The report is distributed across four main sections. Section 2 provides overviews of critical electricity market and carbon pricing concepts, the PJM RTO, the Federal Energy Regulatory Commission (FERC), and RGGI. Section 3 includes an in-depth analysis of three RGGI states and a high-level analysis of two alternative carbon pricing programs, along with key takeaways. Section 4 details the potential market impacts of a potential carbon pricing mechanism in Illinois, including implications for electricity prices, energy generation resources, and carbon emissions. Lastly, section 5 concludes with a summary of recommendations for future analysis.

2. OVERVIEW AND BACKGROUND

A range of institutions and technical issues are relevant to state implementation of carbon pricing mechanisms. Among these are electricity market types, electric grid operators, alternative carbon price structures, and carbon market coordinating entities. This section will briefly discuss institutions and issues that are of critical importance to implementing a carbon pricing mechanism in Illinois.

2.1. KEY ELECTRICITY MARKET AND CARBON PRICING CONCEPTS

This report will refer to several key technical concepts throughout. These concepts include nuances that are important to understanding electricity markets, potential carbon pricing mechanisms, and interactions between the two. The subsections below introduce and define these key concepts at a high level.

2.1.1. Energy Markets versus Capacity Markets

Competitive wholesale electricity markets, such as PJM, use two fundamental market types to match electricity supply and demand. One type is an energy market, in which electric generators are compensated for the volume of electricity they produce and deliver to the wholesale electric grid. This market procures kilowatt-hour units of electricity in response to consumer demand in the near-term (i.e., the next day) and in real-time. (PJM Energy Markets n.d.)

The second market type is a capacity market. A capacity market procures power supply resources in order to ensure that sufficient potential electricity generation (i.e., generating capacity) exists to meet predicted energy demand in future years. (PJM Capacity Markets n.d.) Capacity markets compensate electric generators for simply having assets that are able to generate electricity available to the market if needed, thereby covering a portion of these generators' capital costs. This ensures reliability by compensating the owners of assets that may not be called upon to operate frequently but are nevertheless important to ensure that the market can meet demand at all times.

2.1.2. A Brief Primer on PJM Energy Markets

PJM operates two energy markets, known as the Real-Time Energy Market and the Day-Ahead Market. PJM explains further that the Real-Time market is "a spot market – meaning that the product is procured for immediate delivery – in which current prices…are calculated at five-minute intervals based on actual grid operating conditions." (PJM Energy Markets n.d.) The Day-Ahead market, according to PJM "is a forward market in which hourly [prices] are calculated for the next day based on the amount of energy generators offered to produce, the amount of energy needed by consumers and schedule transactions between buyers and sellers of energy." (PJM Energy Markets n.d.)

In other words, the PJM energy markets work together to match energy generation and consumption every second of every day. The Day-Ahead market addresses *expected* energy demand and generator output the day prior to when it is needed while the Real-Time market serves to address gaps should either actual demand or actual generator output be higher or lower than was expected the day earlier.

2.1.3. A Brief Primer on PJM Capacity Markets

According to PJM, its capacity market, known as the Reliability Pricing Model, can be thought of as an insurance policy for the market. (PJM Capacity Markets n.d.) PJM's capacity market creates a long-term price signal by holding auctions in advance of when it expects capacity to be available. These auctions allow new and existing generators, generator and transmission upgrades, and demand response and energy efficiency resources, to bid the amount of revenue they require in order to be online and available on date three years in the future. (PJM Capacity Markets n.d.)

This market performs an important function by providing an avenue for power supply resources to receive revenues in addition to what they can expect to earn from the energy markets by operating. Such revenue may be important for power supply resources that do not operate for many hours each year but are nonetheless highly reliable when needed and called upon.

The three essential elements of this market are 1) the procurement of capacity three years before it is needed through a competitive auction; 2) locational pricing for capacity that varies to reflect transmission system constraints; and 3) a variable resource requirement curve, the demand formula used to set the price for capacity and the amount of capacity needed. (PJM Capacity Markets n.d.)

2.1.4. Carbon Pricing Design: Cap-and-Trade versus Carbon Tax

The Union of Concerned Scientists explains that carbon pricing is "a market-based strategy for lowering global warming emissions. The aim is to put a price on carbon emissions…so that the costs of climate impacts and the opportunities for low-carbon energy options are better reflected in our production and consumption choices." (Union of Concerned Scientists 2017) There are two fundamental approaches to developing this price for carbon emissions: a cap-and-trade program and a carbon tax.

Put simply, a cap-and-trade program is a set of laws or regulations that cap "carbon emission from particular sectors of the economy (or the whole economy) and issue allowances (or permits to emit carbon) to match the cap." (Union of Concerned Scientists 2017) The cap can be set to achieve a specific goal for emissions and can be constant or declining over time in order to promote decreasing emissions over time. Under such a program, each emission source would be required to hold allowances equal to the emissions they produce. These allowances could initially be allocated for free or sold at auctions administered by a government, and then could later be traded between entities subject to the cap. Ultimately, this would allow some entities to reduce emissions by more than is necessary and receive compensation by selling excess allowances to entities that failed to adequately reduce emissions.

In contrast, a carbon tax establishes a specific fee per unit of carbon emissions, which entities that produce emissions must pay. Unlike a cap-and-trade program, a carbon tax is not a market mechanism, but rather is an administratively determined price on carbon emissions. It could be set, for example, based on the estimated social cost of carbon emissions or at a value that that regulators and/or legislators expect to adequately incentivize innovation and emission reductions.

While a cap-and-trade program defines the maximum emissions allowed in the system and the price for emission allowances depends on how many market participants reduce emissions or depend on purchasing allowances, a carbon tax sets the price for emissions. The resulting emission reductions under the carbon tax are an outcome of the market, with emitting facilities reducing emissions when doing so is cheaper than paying the carbon tax.

2.1.5. Carbon Pricing Scope

As discussed in the prior section, carbon pricing mechanisms can be applied with different scopes. One example is choosing whether to apply a carbon pricing mechanism to one or more specific economic sectors or to the entire economy. There may be advantages to each approach depending on the specific situation.

For example, an economy-wide carbon price in a cap-and-trade program may allow for the most efficient reduction in emissions possible by allowing some sectors to reduce emissions more than is required and others to reduce emissions by a lesser amount. Conversely, focusing on specific economic sectors may allow governments to avoid unnecessarily burdening industries that are unlikely to be able to achieve emission reductions or are heavily exposed to trade with countries that do not have comparable carbon pricing schemes.

An additional question of scope is geographic. That is, does a carbon pricing mechanism aim to reduce emissions within the boundaries of the jurisdiction establishing the price or does it aim to indirectly address sources that lie outside its boundaries but that are responsible for emissions associated with consumption of products within the jurisdiction. This is a relevant question for states that consider establishing carbon prices for electricity and whose electricity grid is connected to areas outside their direct jurisdiction: does the carbon price aim to address only electricity generation within the state or does it aim to address emissions associated with electricity that is generated outside the state but consumed within the state.

A final question of scope is whether policy makers intend a carbon pricing mechanism to be the sole or primary driver of emission reductions or whether it is coupled with complementary policies such as renewable energy procurement mandates or low emission technology incentives. Technology incentives may help businesses adapt more stringent cap-and-trade emissions limit. Renewable energy mandates may be complementary to carbon pricing in driving emission reductions. In both cases, these complementary policies may reflect a different scope with respect to expected emission impact.

2.1.6. Emission Leakage and Border Adjustments

A key factor that complicates carbon pricing mechanisms is the need to address emission leakage. According to PJM "[b]roadly defined, leakage refers to any shift in production, and related emissions, from a regulated jurisdiction to a less-stringently regulated jurisdiction due to differing compliance costs." One such example would be if Illinois implemented carbon pricing that reduced in-state electricity generation from emission-producing sources but unintentionally purchased electricity from a similar source in a neighboring state without a carbon pricing mechanism.

A border adjustment is one way to address emission leakage issues and is straightforward in concept. Implementing a border adjustment amounts to an attempt to apply within-jurisdiction carbon pricing to products being consumed within that jurisdiction but produced elsewhere. In electricity markets, that would mean ensuring that electricity consumed within a state that adopts a carbon pricing mechanism is all subject to the same carbon price, even if generator outside of that state, in order to prevent the state from inadvertently subsidizing emissions in another state.

There are two possible types of border adjustments that policy makers could adopt along with a price. On carbon emissions. The first is a one-way border adjustment, which would adjust electricity prices when the electric grid sends power into a carbon pricing zone. A two-way border adjustment would additionally adjust electricity prices when the grid sends power from a carbon pricing zone into a non carbon pricing one. In either case, the state would likely require the cooperation of the electricity market operator, such as PJM, to actual implemented the adjustment.

To illustrate the two alternatives, consider a scenario where Illinois has a carbon price but neighboring Indiana does not. Under one-way border adjustment, coal-fired electricity from Indiana to Illinois would be subject to an upwards price adjustment to level the playing field with Illinois' in-state generators. In theory this reduces the potential for emissions leakage caused by cheap coal-fired generation from Indiana. Meanwhile, with two-way border adjustment, when a coal-fired generator in Illinois exports power to Indiana, it would receive a *downwards* price adjustment to negate the compliance cost of the Illinois' carbon price. This measure preserves the competitiveness of in-state coal and gas-fired generators in export markets, but in doing so has the potential of reducing the environmental benefits of the carbon price policy.

2.2.THE PJM REGIONAL TRANSIMISSION ORGANIZATION (RTO)

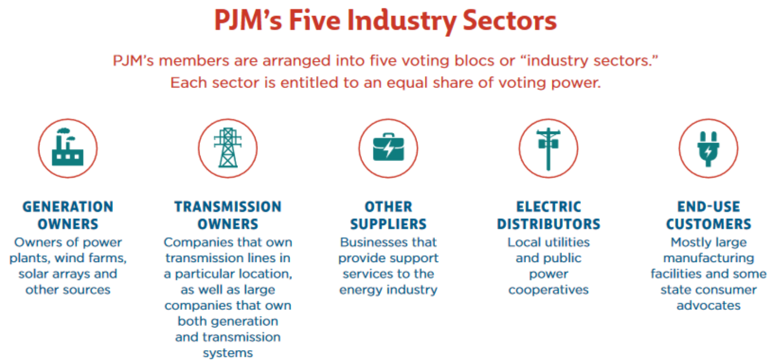
2.2.1. PJM Background and Decision Making

PJM is the RTO serving parts of the mid-Atlantic and Midwestern United States within the Eastern Interconnection power grid. Founded in 1927, PJM coordinates and operates a competitive wholesale electricity market for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, West Virginia, Virginia, and the District of Columbia. PJM runs two markets that are critical to the power needs of its constituent states. The first is the daily/real-time energy market in which PJM buys lowest-cost power including coal, gas, wind, and solar from electricity generators. The second is the capacity market, in which PJM pays generators for a guarantee to provide power up to three years in the future, to ensure grid reliability. These markets are defined and explained in section 2.1.1.

PJM is a limited liability company (LLC) whose decisions are governed by its board and its voting members. PJM has thousands of members who span across a wide range of interested parties, including generation and transmission owners, distributors, larger end-use customers, and advocates. Most of the proposals at PJM must be approved by a majority of its members. However, in practice, market-related decisions are heavily influenced by the PJM's Markets and Reliability Committee, with general membership almost always voting in alignment with the Committee's recommendations.

Finally, proposals that have been approved by PJM membership must also be approved by FERC, which decides whether the proposal represents a "just and reasonable" update to the Federal Power Act (FPA) Section 205 filing. FPA Section 205 represents the governing rules — covering rates, terms, and conditions for transmitting or selling power — PJM must follow for its operations. Once PJM submits a proposal for FERC approval, the general public, including state officials, environmental advocates, and industry representatives can comment on the proposal ahead of FERC's decision.

Figure 1 PJM's members are divided into five major voting blocs. (NRDC n.d.)



2.2.2. Recent Activity Related to Carbon Pricing

In recent years, several PJM states have joined, or are in the process of joining RGGI. These states include Delaware, Maryland, New Jersey, and Virginia. Additionally, Pennsylvania is in the process of joining. Including Pennsylvania, these states represent roughly 55% of total PJM load. In response to these developments, PJM formed a task force in April 2019 in order to determine how to integrate state carbon policies into PJM markets, with a focus on addressing the problem of emissions leakage from RGGI states to non-RGGI states, building on the work done in a white paper the RTO issued in 2017. The task force issued its formal report in January 2021, which included detailed modelling of the generation dispatch for each state under various scenarios, including different RGGI membership scenarios (e.g., considering Virginia and Pennsylvania), carbon price scenarios (e.g., ~$7/ton and ~$15/ton), and border adjustment scenarios (e.g, one-way and two-way border adjustment). Depending on the composition of RGGI states, the impact of border adjustments ranged anywhere from negligible to enormous; Market Analysis section 4.4.5 explores this issue in more detail.

The recent report from the PJM task force indicates that the RTO acknowledges that it may have a role in working with carbon pricing states to undesired mitigate effects on the market. However, PJM has made clear in this report as well as in comments to the media that this report should not be confused as a promotion of or an attempt to implement carbon pricing across the RTO. While we did not find any official remarks on PJM's position on promoting carbon pricing in the future, one senior market strategist for the RTO commented in 2019 that "PJM does not have the ability to set a carbon price. That has to come from a state or the federal government."

So far, there has not yet been any indication that PJM is considering new proposals based on the results found by its task force.

2.2.3. PJM Minimum Offer Price Rule

On December 19, 2019, FERC ordered PJM to substantially expand its Minimum Offer Price Rule (MOPR). MOPR was established in 2006 by PJM in order to prevent new gas generators from artificially depressing capacity auction prices through below-cost bids (for example, to force out competitors). The new FERC order, however, greatly expands the reach and scope of MOPR, directing PJM to establish resource-specific price floors for resources that receive state subsidies, including renewable energy credits and zero emission tax credits. Importantly, resources would not be allowed to reduce their bids based on subsidies received from Renewable Energy Credits (RECs) or Zero Emissions Credits (ZECs).

New generators would receive a price floor equal to the net cost of new entry (Net CONE) across the specific resource, using the both the capital and operating costs of the first year of operation less the energy market revenues. Given the substantial initial capital investment costs of most new generators and without the aforementioned ability to reduce bids by the value of RECs or ZECs, the resulting floor for renewables and nuclear would be significantly higher than it is now. Meanwhile existing resources that have previously cleared the capacity market would be priced at the net avoidable cost rate (Net ACR), reflecting a resource's annual costs — usually resulting in a much more lenient price floor.[1]

PJM has proposed specific dollar/MWh values for each resource using the aforementioned pricing mechanisms. Critics have pointed out that the currently proposed price floors would effectively price new renewables out of the market because their respective price floors — under Net CONE — are well-above previous clearing prices. The impact would be comparatively muted for existing renewables resources, which are exempt from MOPR. On the other hand, existing nuclear generators are projected to be the most adversely impacted, as Net ACR for nuclear plants is expected to be in far excess of current capacity clearing prices and among the highest of all resources. As a result, thousands of MW of nuclear capacity may be at risk of forced retirement as they won't be able to cover their costs just with energy revenues.

Democratic politicians, renewables generators, and environmental activists have criticized MOPR as a policy meant to protect coal and fossil fuel interests by pricing out wind and solar, and with the Biden administration's appointment of Richard Glick as the new FERC Chairman, the policy has clearly fallen out of favor. As a FERC commissioner, Glick was one of MOPR's most vocal and consistent critics.

Despite MOPR coming under fire for the past year and a half, PJM is on schedule to hold its first capacity market auction under MOPR rules in May of this year. (Platts Analytics 2020) Still, the long-term survival of the policy remains unclear. So far, MOPR has weathered several lawsuits, including a challenge by the Illinois Commerce Commission to respond to a prior rehearing request. (Gheorghiu 2020) Several states — including Illinois — are contemplating exiting the capacity markets altogether

[1] For more detail, see https://www.aepenergy.com/2020/10/01/pjms-capacity-market-what-is-mopr/

through a fixed resource requirement, but these proposals have achieved only limited momentum. (Morehouse 2020)

Another avenue for eliminating or curtailing MOPR might come from FERC itself, with some legal observers suggesting that under Chairman Glick, FERC might move against MOPR by asking the court to remand the matter to the commission for review. (Beattie 2020) However, with the commission still comprised of three Republicans and two Democrats, it is hard to say whether Chairman Glick can muster the votes to repeal the policy. While circumstances may change rapidly in the future, for now, policymakers should plan around the assumption that MOPR remains in place.

2.3. THE FEDERAL ENERGY REGULATORY COMMISSION (FERC)

FERC is an independent federal agency that regulates the transmission and sale of wholesale electricity, oil, and natural gas in interstate commerce. FERC also reviews and approves natural gas and hydropower infrastructure proposals. The authority granted to FERC derives from the FPA, Public Utility Regulatory Policies Act, Natural Gas Act, Natural Gas Policy Act, Interstate Commerce Act, and the Energy Policy Act of 2005. (FERC 2018) FERC's regulatory authority as it relates to carbon pricing is discussed further below, including the statutory responsibilities that fall within FERC's jurisdiction.

The Commission is comprised of five Commissioners, appointed by the President. Notwithstanding any vacancies, there are three Commissioners from one political party and two from the other party at any point in time to maintain bipartisanship. Each Commissioner is accorded a vote on orders and filings brought before the Commission.

The Commission's mission and corresponding goals revolve around ensuring efficient, affordable, safe, reliable, and secure energy service to the broader public. To that end, the agency is committed to ensuring just and reasonable rules and policies (rates, terms, and conditions) that are not unduly discriminatory or preferential. In fact, FERC suggested establishing Independent System Operators (ISOs), such as the Midcontinent Independent System Operator (MISO), under Orders 888 and 889 to ensure non-discriminatory access to transmission. (FERC 2021) In Order 2000, FERC also called for the development of RTOs, such as PJM, to manage transmission equitably on a regional basis. (FERC 2021) Both MISO and PJM coordinate the interstate movement of electricity across Illinois and other states, and as a result, are regulated by FERC. (16 U.S.C. § 824 n.d.) This intersection of FERC's regulatory authority over whole electricity markets and state-level policies is central to the conversation regarding carbon pricing.

2.3.1. FERC's Jurisdiction over Carbon Pricing

On October 15, 2020, FERC issued a notice of proposed policy statement to clarify that it has jurisdiction over RTO and ISO wholesale market rules that incorporate a state-determined carbon price. (FERC 2020) However, FERC further specified that "whether the rules proposed in any particular FPA section 205 filing do, in fact, fall under Commission jurisdiction is a determination we will make based on the facts and circumstances in any such proceeding." (FERC 2020) Broadly speaking, FERC's authority over the transmission or sale of electric energy stems from Sections 205 and 206 of the FPA. (Congressional Research Service 2020) Section 205 of the FPA is the avenue through which a proposal that impacts a rate, term, or condition within FERC's service jurisdiction can be amended or approved. (16 U.S.C. § 824d n.d.) Any entity that makes a filing under this section has to demonstrate that the proposal is just and reasonable.

FERC justifies its jurisdiction over these issues based on a U.S. Supreme Court ruling issued in 2016. (FERC v. Electric Power Supply Association 2016) In the ruling, the court upheld FERC Order 745 on demand response resources in wholesale markets, which addressed compensation for demand response participation. (Demand Response Compensation in Organized Wholesale Energy Markets, 134 FERC ¶ 61,187 2011) The Court argued that the order directly affects wholesale electricity rates, and thus, falls under FERC's jurisdiction without weakening state authority over generation facilities. FERC deems that this precedent can apply to wholesale market rules that incorporate a state-determined carbon price.

Additionally, FERC conveyed its encouragement of efforts to incorporate a state-determined carbon price into wholesale electricity markets, and agreed with participants at the Commission's technical conference on this topic that a carbon price could improve the efficiency of markets.

2.3.2. Previous Orders, Rulings, and Filings

FERC has issued various statements and rules and has accepted proposals that have a degree of relevance to the incorporation of a state-determined carbon price. A number of these are briefly highlighted below:

The Commission has previously approved rates that account for environmental compliance costs. In 1994, FERC issued a policy statement and rule to allow public utilities, through end-use customers, to recover the incremental costs of emissions in coordination with transactions to comply with environmental regulations. (FERC 1994) These regulations addressed sulfur dioxide emissions. In 2015, FERC accepted proposed tariff revisions from the CAISO under FPA Section 205 regarding California's Energy Imbalance Market (EIM). (California Independent System Operator Corporation, 153 FERC ¶ 61,087 2015)

The CAISO's proposal allowed a participating resource in the EIM to recover emissions compliance costs under California's cap-and-trade program. This order permits CAISO to consider compliance costs under the cap-and-trade program for those resources outside of CAISO serving demand within the state. In

2018, FERC accepted further, related tariff revisions to "more accurately attribute EIM transfers to the actual generation being incrementally dispatched to serve California load." (California Independent System Operator Corporation, 165 F.E.R.C. ¶ 61,050 2018) The implications of FERC's rulings related to the California cap-and-trade program are discussed further in Section 3.4.1.

In regard to cost increases, the U.S. Court of Appeals for the D.C. Circuit acknowledged in 2017 that increased costs can be just and reasonable. (Advanced Energy Management Alliance v. Federal Energy Regulatory Commission 2017) The court stated this in reference to FERC's approval of PJM's order on proposed tariff revisions to address resource outages in the PJM service region, despite there being sufficient capacity during auctions. (PJM Interconnection, L.L.C., 151 FERC ¶ 61,208 2015) The revisions increased penalties for those who didn't perform when called upon and allowed resources to offer their capacity at higher prices along with other incentives. FERC deemed that the increase in costs was warranted given the improvement in system reliability.

While the previous orders and policy statements do not provide a definitive answer as to whether FERC will approve PJM market rules that incorporate a state-determined carbon pricing regulation and border adjustments in Illinois, it does demonstrate that there is precedent for doing so under cap-and-trade in California and other environmental regulations. Moreover, FERC's policy statement pertaining to carbon pricing sends a signal that market operators could reasonbly incorporate carbon pricing into organized wholesale energy markets.

2.4. THE REGIONAL GREENHOUSE GAS INITIATIVE (RGGI)

2.4.1. Introduction to RGGI

RGGI is the first mandatory cap-and-trade program in the United States to limit carbon dioxide from the power sector. RGGI was established in 2005, and there are currently eleven participating states: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey (withdrew in 2012, re-joined in 2020), New York, Rhode Island, Vermont, and Virginia (starting in 2021). Pennsylvania is also considering joining in 2022.

The RGGI Board of Directors consists of agency heads of energy and environmental regulatory agencies in each RGGI member state. The purpose of RGGI is to provide administrative and technical services to support the development and implementation of each RGGI State's CO_2 Budget Trading Program (i.e., each state's emission allowance program). RGGI doesn't have regulatory or enforcement authority, and all such sovereign authority is reserved within the states.

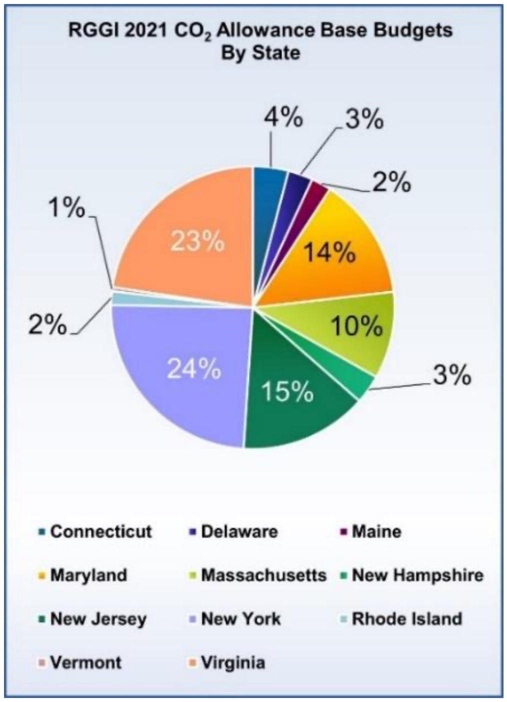
2.4.2. RGGI's Cap-and-Trade System

RGGI establishes a carbon emissions cap for power plants with capacity greater than or equal to 25 megawatts across all member states. Electric generators who meet this criteria are required to possess emissions allowances equal to their carbon emissions in tons during a **three-year control period**, the first of which began from 2009. They can bid for allowances during quarterly auctions held online. Prices of allowances are determined by the supply and demand dynamics in each auction. RGGI has adopted program control methods, such as the Cost Containment Reserve (CCR) and Emissions Containment Reserve (ECR),[2] to ensure that the auctions run effectively and that the market remains stable. These program controls include price thresholds that trigger limited amounts of allowances to be released or taken out of the market if the prices increase above or falls below these thresholds. In addition, the allowances may be transacted in a secondary market.

Allowances are offered by states, and the distribution of allowance cap among states are determined based on analysis of historical and future carbon dioxide emissions and negotiations amongst all the members. The latest allowance distribution is shown in Figure 2. Revenues from the auctions are returned to the states to fund various policy objectives consistent with state enabling legislation; according to RGGI, at least 25 percent of these revenues must be used for "consumer benefit or strategic energy purpose." (Ceres n.d.)

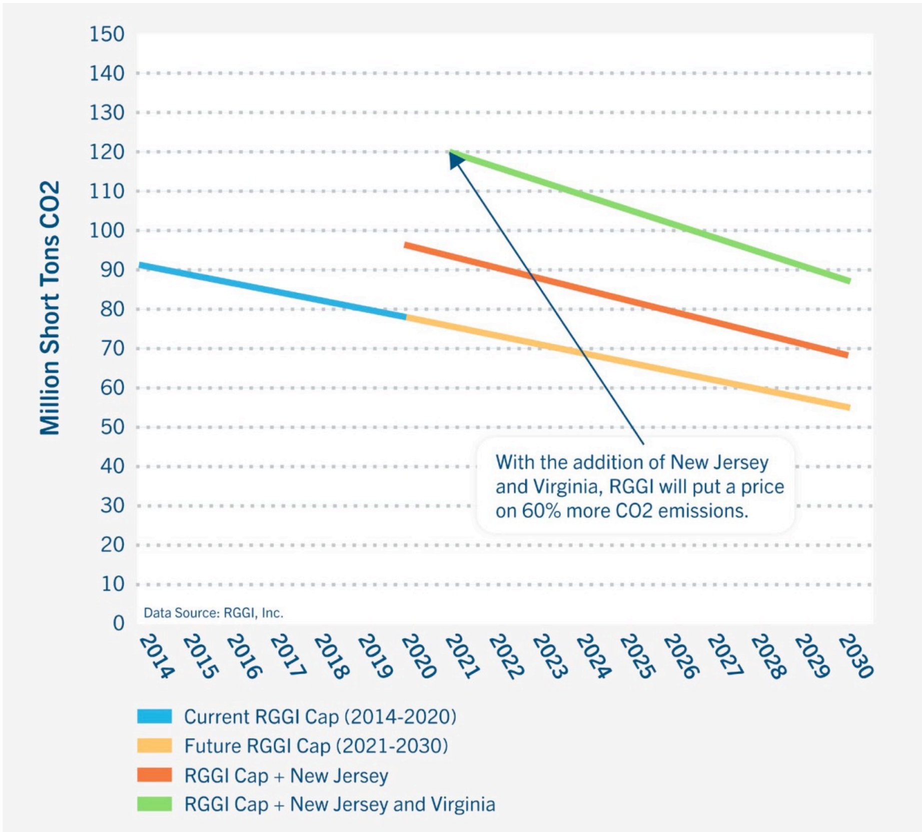
[2] See https://www.rggi.org/program-overview-and-design/elements

Figure 2: 2021 Allowance Distribution by States



A program review is conducted after each control period and is where RGGI members determine the emissions caps for the subsequent control period, and propose any potential changes to the basic rules (the "Model Rule"). Figure 3 shows the change of emissions caps starting from 2009. The latest cap for 2021 is approximately 120 Million short ton CO_2 allowances, as shown by the green line.

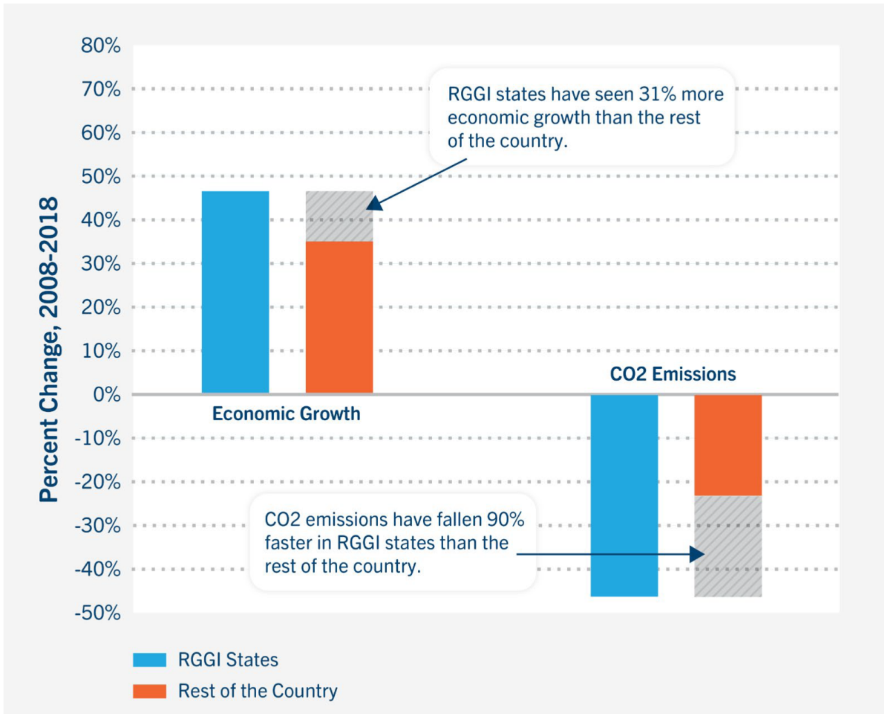
Figure 3: RGGI Emissions Cap, 2014-2030 (Center for Climate and Energy Solutions n.d.)



2.4.3. Impact of RGGI to Date

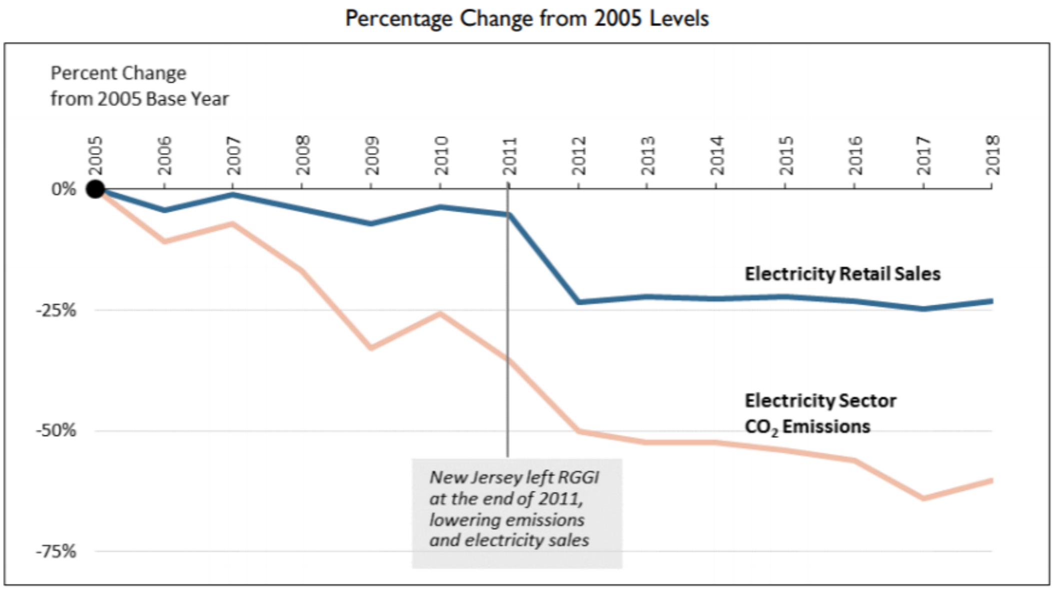
The first achievement that the RGGI states have made is the decoupling of emissions from economic growth. Figure 4 compares the change in economic growth and emissions between RGGI and non-RGGI states, and we can see that RGGI states have seen 30 percent more economic growth while also enjoying a 90 percent faster speed of emissions reduction compared with the rest of the country. While this data does not demonstrate a causal link between RGGI membership and the decoupling of emissions from economic growth, it is nonetheless an important development.

Figure 4: Change in Economic Growth and Emissions, 2008 to 2018 (Acadia Center 2019)



Second, RGGI states have seen the decoupling of carbon emissions reduction from electricity retail sales, implying that the carbon emissions per megawatt-hour has dropped. As shown in Figure 5, after New Jersey left RGGI in 2011, emissions from the electricity sector have dropped by 20%, while electricity sales remained flat. Again, it is important to note that this data does not establish a causal link between RGGI membership and the decoupling of retail electricity sales and carbon emissions. However, the decoupling of emissions from electricity sales and economic growth at a minimum suggests that pricing carbon and reducing emissions do not necessarily harm electric utilities and state economies.

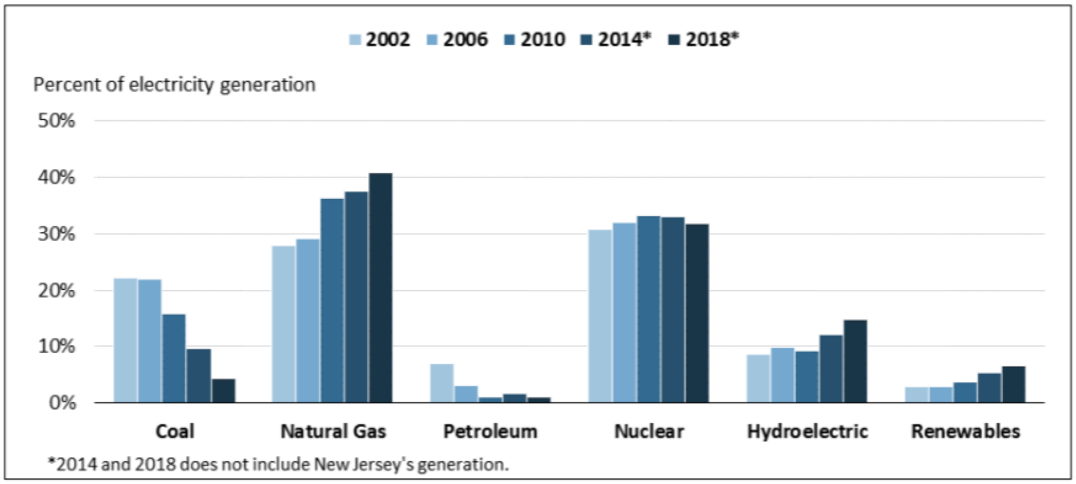
Figure 5: RGGI CO_2 Emissions in Electricity Sector Compared with Electricity Sales (Congressional Research Service, CRS 2019)



Sources: Prepared by CRS; observed state emission data (2000-2017) provided by RGGI at http://www.rggi.org; electricity sales from Energy Information Administration, Electricity Data Browser, https://www.eia.gov/electricity/data/browser/.

Third, RGGI may have contributed to the alteration the energy portfolios of its member states. Figure 6 shows the change of energy mix in RGGI member states since 2002. The share of coal and petroleum dropped significantly below 5%, while natural gas, hydroelectric and renewables gained share gradually.

Figure 6: RGGI States Electricity Generation by Energy Source



Source: Prepared by CRS; data from Energy Information Administration, "Net Generation for Electric Power."
Notes: Renewables include wind, solar, geothermal, and biomass sources. Some sources, including other gases and waste heat, are not included in the above figure, but these account for less than 1% of electricity generation.

Last but not least, there are also other indirect impacts such as health benefits and job creation. A 2018 study by the Analysis Group (Hibbard, et al. 2018) concluded that RGGI states have seen a net economic benefit of $4.7 billion between 2009-2017. An Abt Associates study published in 2017 estimated the cumulative economic value of the public health benefits of RGGI at $5.7 billion. (Abt Associates 2017) Thus, RGGI may have produced large positive impacts for its member states beyond carbon emission reductions.

2.4.4. Emission Leakage in RGGI

Emission leakage is a side effect of RGGI that has been widely discussed. As described in Section 2.1.6, emission leakage is a phenomenon where imported electricity replaces RGGI in-state electricity generation as it can be offered at lower prices, since emissions from imported electricity are not covered under the cap. The quantity of leakage depends on the sources of electricity generation involved in the trade-off. For example, maximum leakage would occur if imported electricity from a coal-fired power plant replaced in-state electricity generated from a zero-emission source. This scenario could occur if the zero-emission electricity is produced at relatively high cost and is economic only because carbon pricing has raised costs for otherwise cheaper fossil fuel-fired generation resources.

In an effort to ameliorate the potential risk of emissions leakage, RGGI participants have stated that they will collaborate to monitor and track relevant data to evaluate potential leakage, and work to address any emissions leakage that may be identified . RGGI produces annual electricity monitoring reports that provide estimates of emissions leakage discussion of these issues. According to a recent monitoring report from November 2019, while annual average electric generation from all non-RGGI sources that served

RGGI load increased by 9.7 percent between 2015-2017 and 2006-2008, carbon emissions generated by those non-RGGI sources actually decreased by 4.6 percent. (RGGI Inc. 2019) Nevertheless, emissions leakage will likely remain a topic of discussion going forward, particularly as RGGI adjusts emission caps and incorporates new member states.

2.4.5. Prerequisites to Joining RGGI

Although there are no mandatory geographic constraints on membership, it is expected that state-level legislation will align with RGGI regulations. Virginia waited to join RGGI until mid-2020 to coincide with the expiration of a state budget plan that would have conflicted with RGGI. (Sierra Club 2019), (Cornelius 2020) New Jersey also adopted two relevant regulations before it rejoined in 2020 to ensure consistency of state policy with the RGGI Model Rule in 2019. (ICAP 2019) In Pennsylvania, which is contemplating joining in 2022, there is still an ongoing fight between the Governor and the legislature over regulations about joining RGGI. (McDevitt 2020)

3. STATE CASE STUDIES

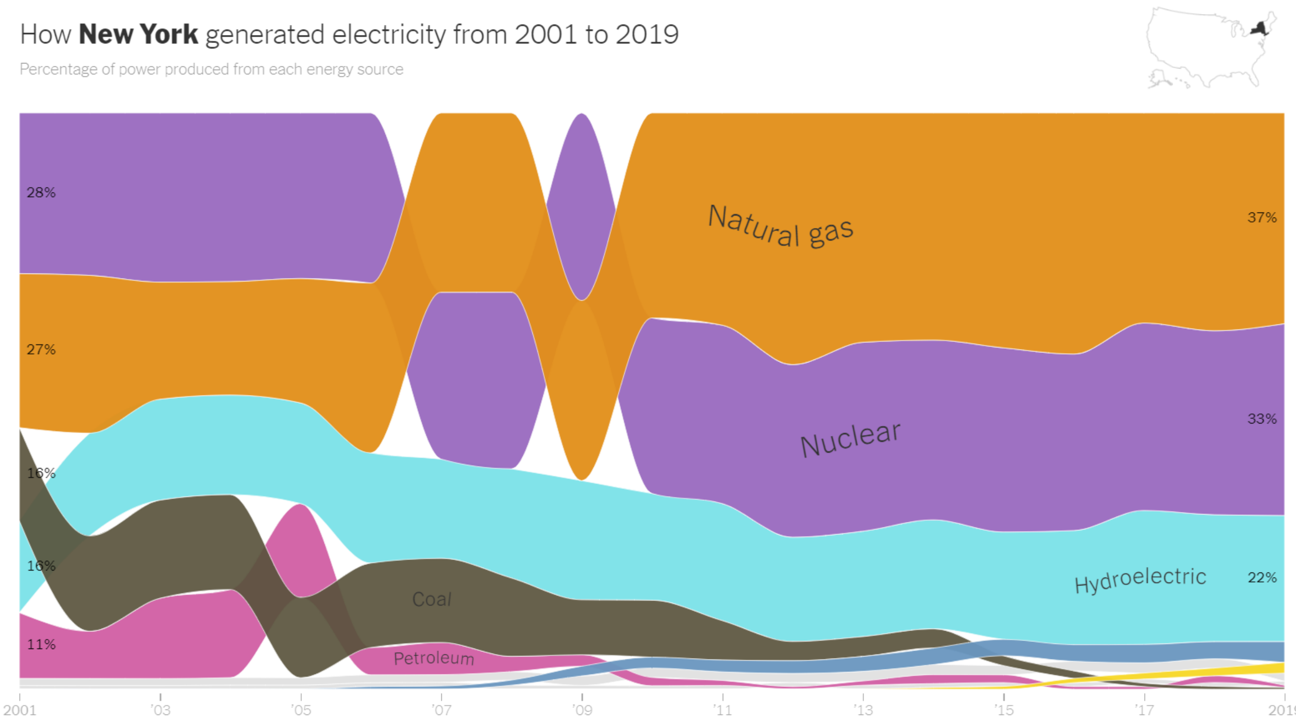
To further investigate the impact of RGGI on its members, we have conducted three case studies of RGGI member states. This report focuses on New York, New Jersey, and Virginia out of the 11 RGGI states because each offers different characteristics that are relevant to the State of Illinois and how it would potentially interact with RGGI. New York is the largest economy and the largest carbon emitter in RGGI, was a founding member of RGGI, and has been a RGGI member for over 10 years. New Jersey is, like Illinois, a PJM member, was a founding RGGI member, but withdrew from RGGI in 2012 and rejoined in 2020. Virginia is also a PJM member and is the newest member of RGGI, which just joined in January 2021. Virginia is also the second biggest emitter in RGGI and offers a generation mix with a number of commonalities with Illinois. Each state, therefore, offers different potential lessons learned based on their experiences with RGGI.

3.1. NEW YORK

3.1.1. Electricity Generation and Energy Consumption Profile of New York

As shown in Figure 7, during the last 20 years, nuclear and natural gas have long been the two largest electricity generation sources in New York (NY). Hydroelectricity in the state is third largest generation source. Total electric generation in 2019 in New York was about 131.6 million megawatt hours. (EIA 2020)

Figure 7: Flow Chart of New York State Energy Generation Mix, 2001-2019[3]



In 2019, New York ranked last but one among all the states in terms of energy consumption per capita. (EIA 2020)

3.1.2. State-level Objectives

In July 2019, New York State Governor Cuomo signed the Climate Leadership and Community Protection Act (CLCPA), which established four major goals in terms of GHG emissions: (State of New York n.d.)

- Limit statewide GHG emissions by 40% of 1990 levels by 2030 and 85% by 2050
- A plan to achieve net zero greenhouse gas emissions across New York State's economy
- 70% renewable electricity by 2030
- 100% zero emission electricity by 2040

The CLCPA also set specific procurement goals for renewable energy: (State of New York n.d.)

- 9,000 MW of offshore wind by 2035

[3] See: https://www.nytimes.com/interactive/2020/10/28/climate/how-electricity-generation-changed-in-your-state-election.html

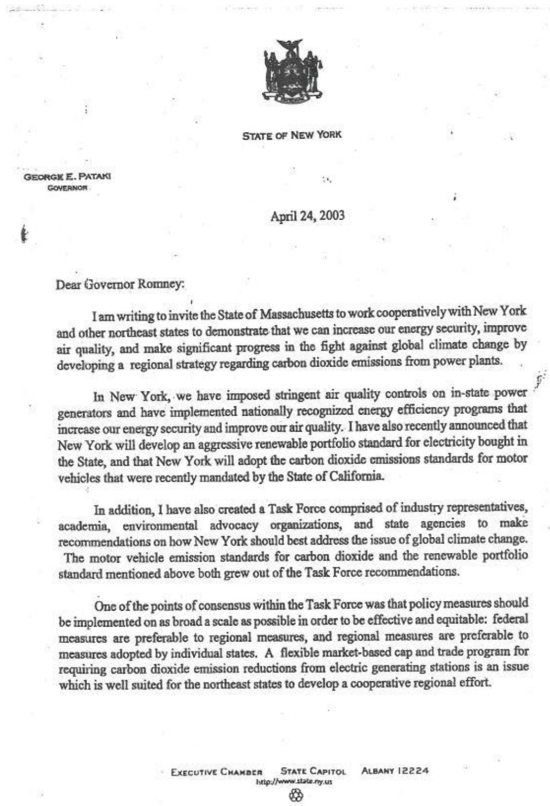
- 6,000 MW of distributed solar generation by 2025
- 3,000 MW of state-wide energy storage capacity by 2030

These goals are among the most aggressive across all U.S. states. In order to realize these goals, New York must take advantage of all available tools for climate action, including and beyond RGGI.

3.1.3. Process of New York Joining RGGI

New York was the state that initiated the establishment of RGGI in April 2003, when New York Governor George Pataki invited nine other northeast states to develop a regional carbon emission cap-and-trade program for power plants (see Figure 8). Representatives from the region's environmental and energy regulatory agencies began monthly meetings in September 2003 to discuss, research and analyze information and potential program design recommendations. In January of 2004, the states launched a multi-year stakeholder process that sought input from power companies, electricity consumers, and environmental advocates throughout the prospective RGGI region to present analysis undertaken by the states and their contractors, and obtain feedback and input on program design issues. In December 2005, the Governors signed a Memorandum of Understanding (MOU) which provides the outlines of RGGI, including the framework for a cap-and-trade model rule. (RGGI Inc. 2021)

Figure 8: An excerpt from the invitation former NY Governor George Pataki wrote to former MA Governor Mitt Romney to form a regional emissions reduction program



STATE OF NEW YORK

GEORGE E. PATAKI
GOVERNOR

April 24, 2003

Dear Governor Romney:

I am writing to invite the State of Massachusetts to work cooperatively with New York and other northeast states to demonstrate that we can increase our energy security, improve air quality, and make significant progress in the fight against global climate change by developing a regional strategy regarding carbon dioxide emissions from power plants.

In New York, we have imposed stringent air quality controls on in-state power generators and have implemented nationally recognized energy efficiency programs that increase our energy security and improve our air quality. I have also recently announced that New York will develop an aggressive renewable portfolio standard for electricity bought in the State, and that New York will adopt the carbon dioxide emissions standards for motor vehicles that were recently mandated by the State of California.

In addition, I have also created a Task Force comprised of industry representatives, academia, environmental advocacy organizations, and state agencies to make recommendations on how New York should best address the issue of global climate change. The motor vehicle emission standards for carbon dioxide and the renewable portfolio standard mentioned above both grew out of the Task Force recommendations.

One of the points of consensus within the Task Force was that policy measures should be implemented on as broad a scale as possible in order to be effective and equitable: federal measures are preferable to regional measures, and regional measures are preferable to measures adopted by individual states. A flexible market-based cap and trade program for requiring carbon dioxide emission reductions from electric generating stations is an issue which is well suited for the northeast states to develop a cooperative regional effort.

EXECUTIVE CHAMBER STATE CAPITOL ALBANY 12224
http://www.state.ny.us

3.1.4. How New York has Implemented RGGI

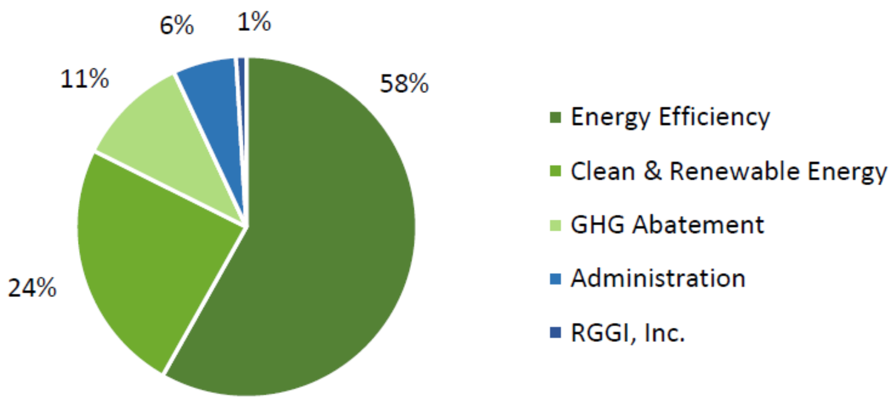
Two New York State policy measures established the RGGI framework. First, 6 NYCRR (New York Codes, Rules and Regulations) Part 24 enabled the Department of Environmental Conservation (DEC) to establish NY's CO_2 Budget Trading Program, the state's share of the total regional cap, as well as program compliance responsibilities and other program aspects.

Second, 21 NYCRR Part 507 assigned authority for conducting emission allowance auctions to NYSERDA (New York State Energy Research & Development Authority). NYSERDA is responsible for administering quarterly auctions of emissions allowances, and reinvesting the proceeds from the auctions. Apart from these two major authorities, other units such as Department of Public Service (DPS) and Department of Environmental Protection (DEP) also play supportive roles in the framework.

3.1.5. Use of the State Revenue from RGGI

In NY state, the proceeds from RGGI are invested to administer energy efficiency, renewable energy, programs for disadvantaged communities, innovative carbon abatement programs, and to cover the costs to administer such programs. One of the successful programs is Green Jobs Green New York, which is designed to serve single family homes, multi-family housing, nonprofits, and small commercial businesses with low-cost financing for education and training opportunities for clean energy jobs. As of March 2020, New York has received over $1.3B in proceeds, over 80% of which are spent on energy efficiency and clean energy projects (see Figure 9).

Figure 9: New York RGGI Investments by Category, as of 2018 (RGGI Inc. 2020)



3.1.6. Benefits and Success of New York under RGGI

New York's robust record of climate action includes helping to establish RGGI as North America's first market-based program to reduce carbon emissions. New York State has reduced electricity emissions by 51 percent since 1990, with a 60 percent reduction from 2005 to 2019 in greenhouse gas emissions from sources covered by the RGGI program. (RGGI Inc. 2020)

3.1.7. Additional Carbon Pricing Policy Measures

The New York State Indepdendent System Operator (NYISO), which operates New York's wholesale electricity market, issued a proposal to implement a state-wide carbon pricing mechanism called "carbon adder" in its electricity market in December 2018 in accordance with the CLCPA. (NYISO 2018) If the proposal is approved by both FERC and state legislature, this additional carbon pricing mechanism could be established and implemented within two years. There have been discussions around the pros and cons of this proposed policy and the interplay between this policy and the RGGI system.

In addition, in December 2020 New York extended the applicability of RGGI from power plants with capacity of 25 Megawatt and above to those with 15 Megawatt and above. This extension was done by amending the NYCRR Part 200 and 242 under Department of Environmental Conservation.

3.1.8. The “Carbon Adder” Policy and its Projected Impact

The current level of policy effort in New York may not suffice to meet the CLCPA goals in the coming decades. Additionally, the current RGGI carbon price level is not consistent with fully internalizing the social externality cost imposed by carbon emissions. Therefore, NYISO has proposed the “carbon adder” policy to set the state’s total carbon price price level equal to the Social Cost of Carbon (SCC), which will be about six times larger, as shown in Table 1. (NYISO 2018)

Table 1: Social Cost of Carbon versus RGGI Allowance Prices, 2020-2030 (projected)

	Gross SCC	RGGI, Inc.	Net SCC
	$nominal/US-ton	$nominal/US-ton	$nominal/US-ton
2020	47.30	6.56	40.74
2021	48.30	6.98	41.32
2022	50.48	7.39	43.09
2023	52.74	7.81	44.93
2024	55.07	8.45	46.62
2025	57.48	9.09	48.39
2026	59.96	9.73	50.23
2027	62.52	10.35	52.18
2028	65.17	10.96	54.20
2029	66.54	11.58	54.96
2030	69.32	12.55	56.77

There are controversies in the discussion of the projected impacts of this policy. Some reports, such as one by the Analysis Group (Tierney and Hibbard 2019) and one by the Brattle Group (Newell, et al. 2018) emphasized the advantages of this policy, such as enhanced public health due to less air pollution, benefits in community resilience and environmental justice, and a demonstration effect within and out of New York State, and noted that there will be minor effect on consumer costs. Others, such as one from the Environment Defense Fund (Gökçe Akın-Olçum 2019) and one from the Duke University Nicholas School (Stutt 2019) have argued that this policy would introduce dramatic cost surges while having a negligible effect on emissions reduction.

There are also several other potential drawbacks of this policy. First, this policy only regulates the electricity industry and therefore could lead to perverse results, especially in the transportation industry, where entities or individuals switch away from relatively clean electricity to fuels such as propane and oil. This policy would aslo only address New York State and would hence it put the state at a competitive disadvantage against other states, including even other RGGI members, for any product that include electricity as an input. Finally, this policy could add cost to consumers with little to no incremental carbon emission reductions.

3.2. NEW JERSEY

3.2.1. Policy History

Among RGGI member states, the Garden State has the dubious honor of being the only one to have withdrawn after joining the program, before finally rejoining years later. As a result, even though New Jersey was one of the founding member states of RGGI, it has only been a member for a few years in total.

New Jersey (NJ) was one of the seven states that signed the original 2005 MOU that would eventually evolve into the RGGI Model Rule, which was jointly published by the seven states the following year. (RGGI Inc. 2021) In 2007, the state legislature adopted the Global Warming Solutions Fund Act (GWSFA), thereby authorizing participation in the RGGI cap-and-trade program. The GWSFA also directed that the allowance auction proceeds should be distributed towards a variety of environmental projects. The program as established would help meet the goals outlined in the Global Warming Response Act (2007), which called for an 80% reduction in GHGs from baseline year 2006 to 2050. Unfortunately, after these promising beginnings under successive Governors Richard Codey and Jon Corzine, the state underwent a rapid policy shift under Governor Chris Christie. Starting in early 2010, Governor Christie ordered that all RGGI auction funds would be directed towards balancing the state budget rather than the projects outlined in the GWSFA guidelines. (Gruen 2010) In 2011, Governor Christie ordered that the state withdraw from RGGI altogether, effective January 2012. (Christie 2011)

It wasn't until 2018 that NJ began the process to rejoin RGGI, under Executive Order 07 from newly inaugurated Governor Phil Murphy. (Murphy 2019) The process of completing and adopting the new Global Warming Solutions Fund Rule (NJSA 7:27D) and CO_2 Budget Trade Rule (NJAC 7:27C) as well as the administrative process to reenter the RGGI auction took about two years, with NJ finally participating in the first auction of 2020 — eight years after its withdrawal from RGGI.

Figure 10 Rejoining RGGI was a long process (NJ Board of Public Utilities 2018)

3.2.2. Energy Background

As of 2019, electric generation represented approximately 20 percent of the emissions output in New Jersey — 19.2 million metric tons of CO2 equivalent (MtCO2e) out of a total 97.7 MtCO2e. (NJ Department of Environmental Protection 2020) These emissions are the product of 71,019 GWh of locally generated electricity, plus an additional 2,898 GWh imported from out-of-state. Power in NJ is mostly sourced from nuclear power and natural gas, which together comprise 94 percent of in-state generation. The two nuclear plants operating in NJ, Salem and Hope Creek, produce 38 percent of in-state generation, while combined cycle gas turbine (CCGT) plants pull the lion's share of the weight at 57 percent. (EIA 2021) Renewables — mostly solar — represent ~1.5 percent of the generation mix, roughly on par with the remaining coal generation in the state.

Although the state's reliance on natural gas might not be considered ideal for the environment, NJ has already come a long way from 2006, which is the baseline year for its Global Warming Response Act. At that time, in-state generation represented only 3/4 of total power consumption (60,700 out of 81,897 GWh) and was considerably dirtier than the state's generation mix today. With the Oyster Creek plant still in operation, nuclear power represented 54 percent of the local generation mix, but the state relied heavily on coal, which accounted for 18 percent of local generation. The remaining generation was sourced from gas; in total, in-state generation accounted for 18.5 $MtCO_2e$ of emissions — nearly the same as 2019 but for 26 percent fewer gigawatt-hours. Worse, imported electricity, which accounted for the remainder quarter of power demand was even dirtier, accounting for an additional 11.7 $MtCO_2e$. (NJ Department of Environmental Protection 2009) Since 2006, NJ has retired nearly all of its coal plants and now meets nearly all of its demand with in-state generation, reducing its reliance on imported power.

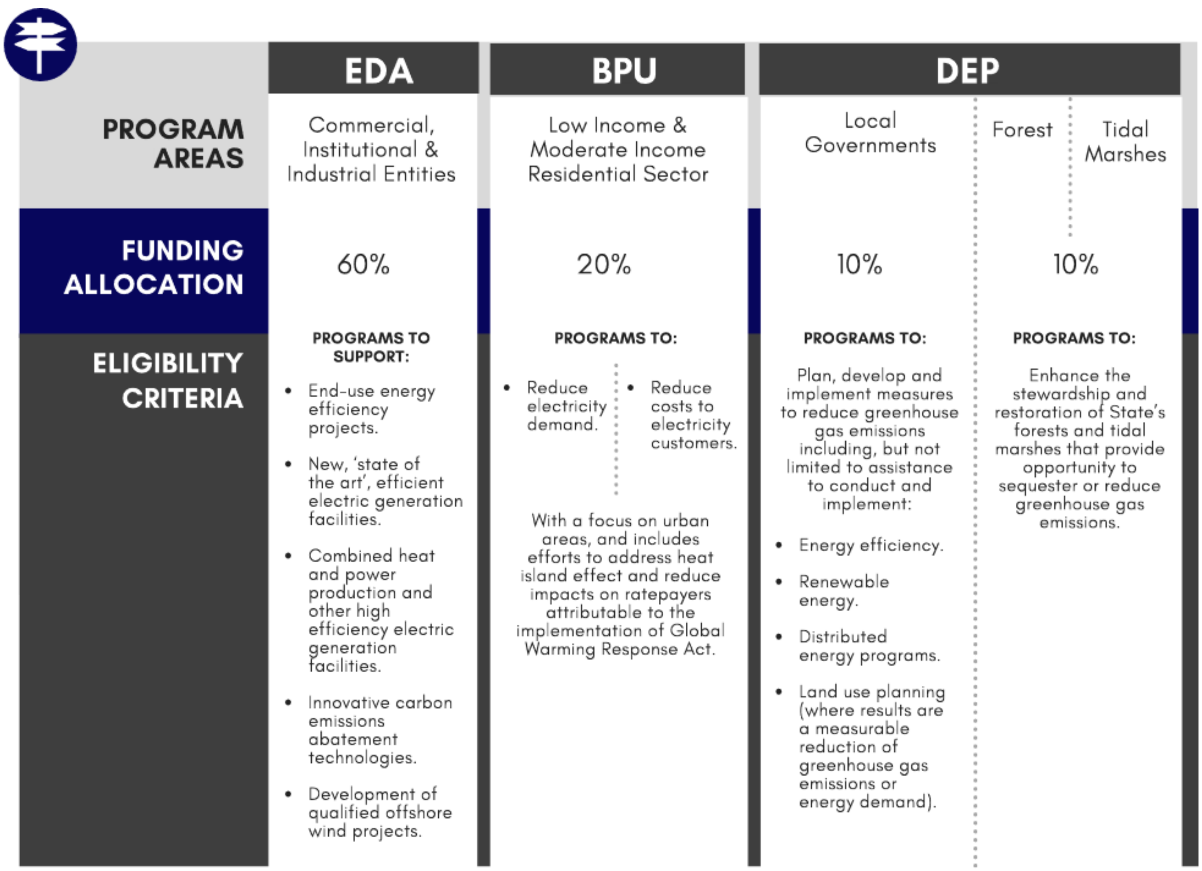
3.2.3. Policy Implementation

New Jersey has set an initial cap of 18 million $MtCO_2e$ for 2020, which decreased to 17.46 $MtCO_2e$ in 2021 and will eventually reach 12.6 $MtCO_2e$ by 2030. (Insider NJ 2019) The state emitted 19.2 MtCO2e from electric generation — including both in-state generation and imported power — in 2019 (NJ

Department of Environmental Protection 2021), compared with 31 $MtCO_2e$ in 2006 (NJ Department of Environmental Protection 2009). In other words, the state plans to reduce emissions related to electric generation by just shy of 60 percent by 2030, compared to the 2006 baseline.

RGGI auction proceeds in NJ are governed by the Global Warming Solutions Fund Rule, which outlines six objectives for projects that receive funding from proceeds; these are outlined in NJAC 7:27D and include reducing energy usage, reducing GHG emissions, and promoting environmental justice. The rule provides the following guidelines for funding allocation amongst the relevant agencies: the Economic Development Authority, the Board of Public Utilities, and the Department of Environmental Protection.

Figure 11: New Jersey Auction Proceeds Investment Scheme (NJ Department of Environmental Protection n.d.)



However, these guidelines appear to be somewhat flexible; for its first strategic funding plan — effective April 2020 to December 2022 — NJ decided to invest 75 percent of auction proceeds towards electrifying the state's transportation sector, 15% on the creation of a green bank, and 10 percent on carbon sequestration in the state's wetlands. (Clean Water Action 2020)

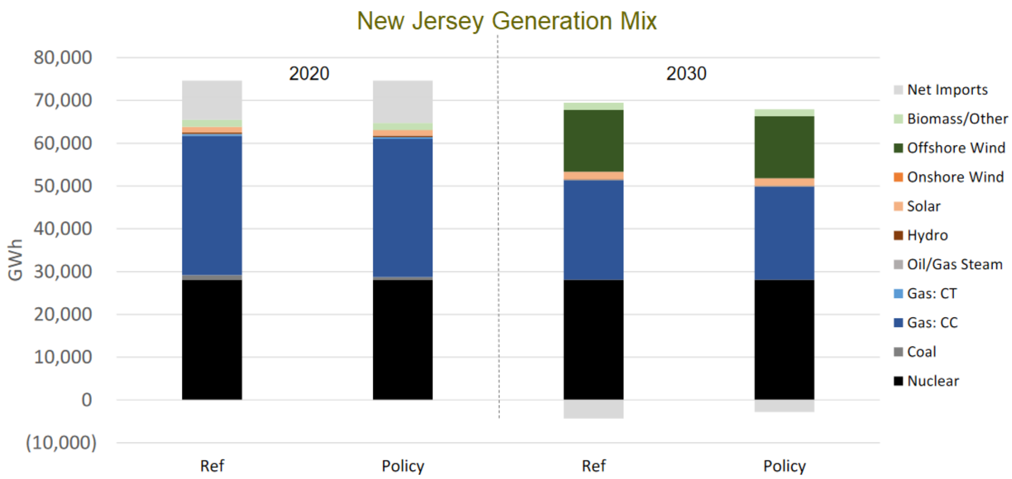
3.2.4. Modeled Outcomes

Given that New Jersey rejoined RGGI just one year ago, the effect that the cap-and-trade program has on the state's generation mix, emissions, and energy prices remains to be seen.

One import factor to consider is that NJ has already achieved much of its "low hanging fruit" in terms of coal-to-gas switching in the electric generation mix; as of 2020, coal represents less than 2% of NJ's generation output. The impact of a carbon price is relatively muted for CCGT plants compared to coal plants, due to the former's comparatively smaller carbon footprint. So, while the coal plants of yesteryear might have been easy targets for RGGI to show a tangible impact to power generation, it will be more challenging to displace gas powered generation.

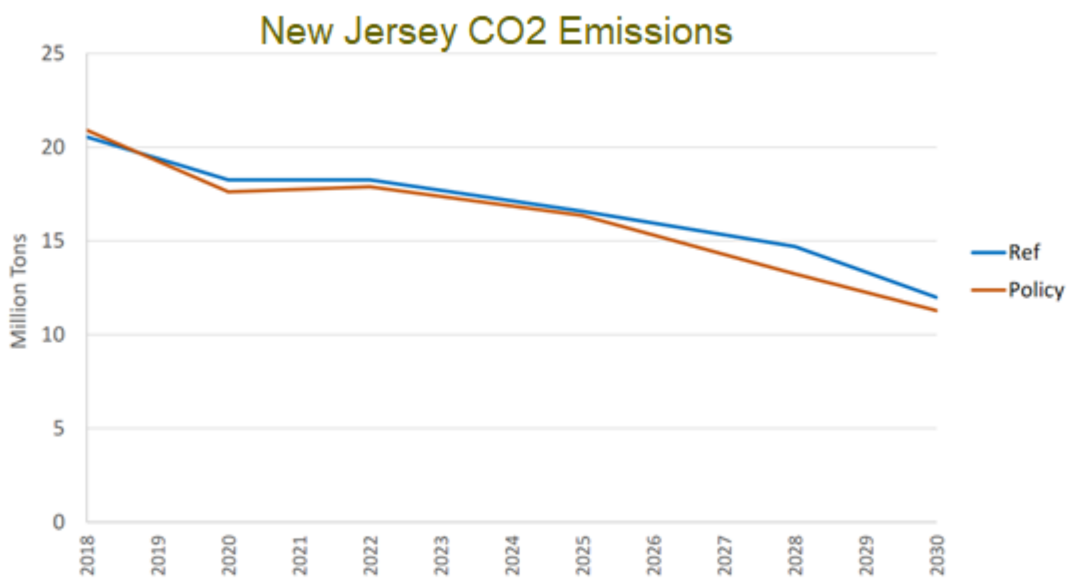
Indeed, a forecast prepared by ICF at the request of the NJ Board of Public Utilities (BPU) in 2018 shows that the projected impact on electric generation and generating capacity is almost negligible. That is not to say that power generation in NJ will not become cleaner over time, but rather, the outcome will be essentially the same in the reference case, where NJ does not join RGGI, and the policy case, where NJ and Virginia join RGGI. For example, the ICF forecasts NJ's flagship offshore wind projects (currently in the planning stage) to bring 3,500 MW of capacity additions online by 2030 regardless of whether NJ is a RGGI state or not. The forecasted incremental renewable capacity additions under the policy case and the reference case are exactly the same, and the difference in actual renewables generation in 2030 is just 4 GWh: 16,622 GWh total in the policy caase compared to 16,618 GWh in the reference case.

Figure 12 Generation is nearly identical in both cases, though CCGT generation decreases slightly in the policy case (ICF 2019)



With regard to fossil fuels generation resources, joining RGGI does not result in any additional plant retirements, but it does marginally reduce coal and gas generator output. By 2030, conventional generation is 1,500 GWh lower annually in the policy case than in the reference case; in other words, if NJ joins RGGI, it will reduce coal and gas generation by 2.8 percent compared to business as usual — a product of lower demand due to energy efficiency increases.

Figure 13 CO_2 emissions decrease slightly under RGGI (ICF 2019)



As for energy and capacity prices, energy prices (2017 $/MWh) are forecasted to be about $1 higher in the policy case throughout the coming decade, while capacity prices will remain nearly identical. Meanwhile, the ICF forecasts that under RGGI, NJ will decrease CO_2 emissions by an additional 6 percent compared to the reference case.

Overall, NJ's reentry into RGGI is expected to decrease the state's use of fossil fuels as well as its overall carbon footprint, while increasing electricity prices. However, at least in some part because of NJ's already relatively clean generation mix of primarily nuclear and gas power, these changes are so small that their impact to electricity markets can be described as marginal, if not negligible.

3.2.5. Other Policies

RGGI is not the only environmental initiative in New Jersey. The state has enacted a number of policies aimed at achieving its Global Warming Response Act (2007) goals of reducing GHG emissions by 80 percent in 2050 relative to 2006 levels, as well as its Renewable Portfolio Standards of 50 percent clean electricity by 2030. (NJ Dept of Environmental Protection 2021) As mentioned earlier, the Murphy administration is currently in the early stages of planning and accepting bids for offshore wind projects — something which has already been baked into the ICF modelling for future renewables capacity additions.

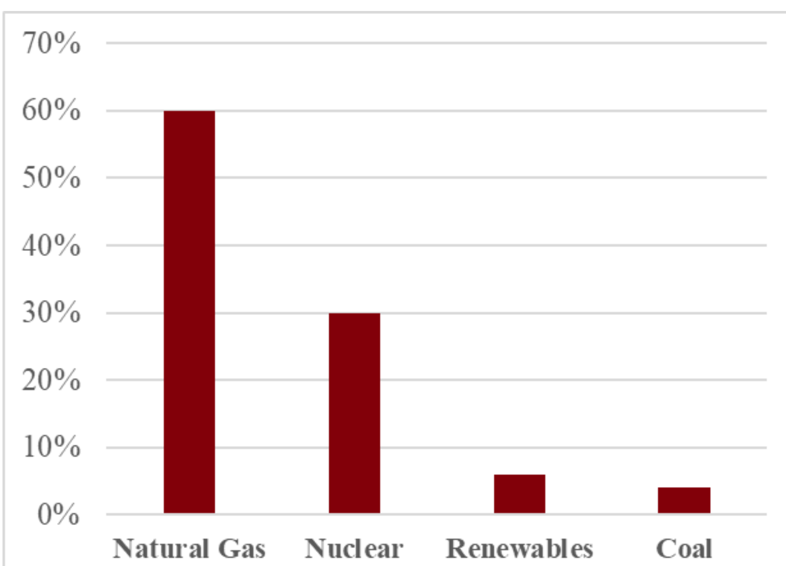
Transportation represents 41 percent of the state's GHG emissions, and under Governor Phil Murphy the state has acted accordingly with a series of policies. These include a variety of initiatives promoting adoption of electric vehicles (EVs), including the Drive Green New Jersey Initiative, a sales tax exemption on EV sales, and policies encouraging employers to install EV charging stations. NJ is also a member of the Northeast States for Coordinated Air Use Management (NESCAUM), which among other goals includes a commitment to place millions of zero-emission vehicles on the road by 2025. Under Governor Murphy, NJ has also updated its Protecting Against Climate Threat (PACT) laws, which now include greater GHG monitoring and reporting rules, as well as new land use regulations.

3.3. VIRGINIA

3.3.1. Overview of Virginia's Energy Profile

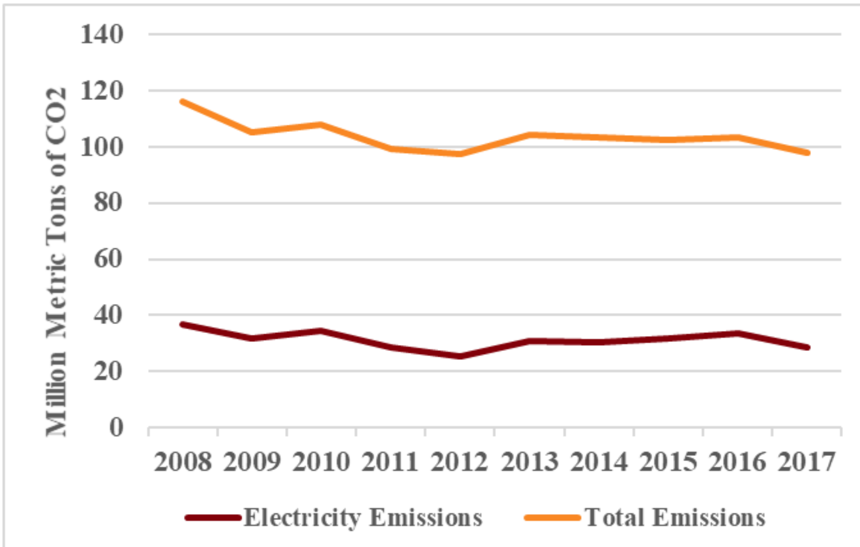
Virginia is one of 13 states that is located within the PJM Interconnection. In 2019, the state generated 60 percent of its electricity from natural gas, 30 percent from nuclear power plants, 6 percent from renewable energy sources, and 4 percent from coal-fired power plants as seen in Figure 14. (U.S. Energy Information Administration 2020) The net electricity generation makeup in Virginia is significantly different than in Illinois. Nuclear power fueled 54 percent of the electricity generated in Illinois, coal plants supplied 27%, natural gas provided 10 percent, and wind energy generated the remaining 9 percent. (U.S. Energy Information Administration 2020) Virginia was also one of the fourth-largest electricity importers in the U.S. in 2019, which can influence carbon emissions leakage under a cap-and-trade program if the state's excess demand is met with electricity from fossil-fuel dependent states. (U.S. Energy Information Administration 2020) In contrast, Illinois was the third largest exporter of electricity. Despite these differences, in both states in 2020, the average retail electricity price to customers across all end-use sectors was below the national average. (U.S. Energy Information Administration 2021)

Figure 14: Virginia's Electricity Generation by Source, 2019



While the sections below provide additional detail on Virginia's actions to target carbon emissions from power generation, it is worth highlighting that emissions in the state largely stem from the transportation sector followed by the electric power sector. Figure 15 depicts how carbon emissions associated with electricity have trended in recent years before the implementation of RGGI. (U.S. Energy Information Administration 2021)

Figure 15: Carbon Dioxide Emissions in Virginia



3.3.2. Policy Implementation Associated with RGGI

In 2017, Governor Terence R. McAuliffe issued Executive Directive 11, which directed Virginia's Department of Environmental Quality (DEQ) to develop a regulation to abate, control, and limit carbon emissions from electric power facilities. (McAuliffe 2017) The executive order also declared that the regulation should be trading-ready for a multi-state trading program. The proposed regulation, Virginia's CO_2 Budget Trading Program, specified participation in RGGI starting in 2020. However, the state was unable to join RGGI at the time, given that there was opposition from the legislative branch.

In 2019, the Virginia General Assembly included a temporary provision in the state budget that prohibited the state from allocating funds for the purposes of participating in RGGI or accepting any revenues from the program. (Virginia General Assembly 2019) Governor Ralph Northam signed the state budget out of respect for the General Assembly's constitutional authority over appropriations, but asked that the DEQ identify a way to implement a consignment auction, where free allowances could be granted. This would no longer be necessary once future legislation passed.

In 2020, when the legislative composition of the state changed, the General Assembly passed a number of important bills targeting carbon emissions and electricity generation, which were signed into law by Governor Northam. One bill, the Clean Energy and Community Flood Preparedness Act, provided authorization for the DEQ to establish a cap-and-trade program for the electric power sector in compliance with the RGGI Model Rule. (SB 1027, Clean Energy and Community Flood Preparedness Act 2020). The bill included provisions to govern the distribution of cap-and-trade revenues—50 percent for energy efficiency programs for low-income residents, 45 percent for flood prevention and protection, and 5 percent for administrative costs. While the bill would allow for utilities to recover the costs of allowances from ratepayers, the DEQ estimates that RGGI participation will provide revenue \$104-\$109 million annually over the next six fiscal years. (Virginia Department of Planning and Budget 2020)

Following the passage of the Clean Energy and Community Flood Preparedness Act, the DEQ amended and finalized the proposed regulation establishing Virginia's component of the CO_2 Budget Trading Program. (CO2 Budget Trading Program, 9 VAC 5-140 2020) The rule stipulated that Virginia would begin participating in RGGI in 2021, where the current emissions cap for the state would be 27.16 million tons of CO_2 allowances with a 3% decrease annually resulting in a 27.8% decrease between 2021-2030, as shown in Table 2.

Table 2: Carbon Dioxide Base Budgets in Virginia

Years	Million Tons of CO_2
2021	27.16
2022	26.32
2023	25.48
2024	24.64
2025	23.80
2026	22.96
2027	22.12
2028	21.28
2029	20.44
2030	19.60

3.3.3. Impacts of RGGI Participation

The actual impacts of participation in RGGI are not yet observable given that Virginia recently joined RGGI. However, there were estimates produced in 2017 in conjunction with the proposed Virginia CO_2 Budget Trading Program. (Virginia Department of Planning and Budget 2017) The DEQ projections regarding electricity bill impacts were conducted by the Analysis Group, using the Integrated Planning Model developed by the ICF. For example, the model forecasted an increase in the average monthly electricity bill for residential consumers by 0.3 percent to 0.7 percent ($0.53 to $1.19 per month) through 2031 depending on the assumptions used. (Virginia Department of Planning and Budget 2017, 8) In contrast, the State Corporation Commission (SCC), which regulates public utilities, estimated "that a typical monthly residential bill will see an average increase between $7 and $12, over the 2019-2043 time period," (Virginia State Corporation Commission 2019, 3) if Virginia participates in RGGI. The difference in estimates from the SCC were due to modeling and the time period used. SCC modeled Dominion Energy, Virginia's largest IOU, as a vertically integrated utility that both buys and sells electricity (i.e., owns fossil fuel resources)—different from the market structure in most of the other RGGI states. DEQ, through the Analysis Group, modeled Dominion as only a buyer of electricity. Ultimately, both the DEQ and the SCC projected increases in electricity bills, with the SCC projecting a more significant increase.

In addition, under the finalized regulation, current C_2 emissions from the electric power sector are expected to fall by nearly a third to 19.60 million tons in 2030 as noted in Table 2. The cap-and-trade program will be one of many emission reduction drivers in the state. The other drivers are discussed in the next section.

3.3.4. Other Relevant Policies

Virginia has passed recent legislation targeting carbon emissions from the electric power sector. The state initially had a voluntary renewables target of 15% by 2025, but in 2020, set a statutory Renewable Portfolio Standard (RPS) that would require electricity to come from 100% renewable sources by 2050. The Virginia Clean Economy Act established the RPS and included language to establish energy efficiency standards, advance offshore wind, and advance solar and distributed generation. (SB 851, Virginia Clean Economy Act 2020) Similarly, the Commonwealth Energy Policy established statutory GHG emissions reductions standards that would require net-zero carbon emissions across all sectors by 2045. (HB 714, Virginia Energy Plan and Commonwealth Energy Policy 2020) The Policy also enacted clean energy standards to reach net-zero carbon specifically in the electric power sector by 2040. While there are other climate-related policies within the state, the aforementioned policies represent the relevant, complementary approaches that Virginia has taken.

3.4.CARBON PRICING OUTSIDE RGGI

Carbon pricing mechanisms can be applied with a variety of different scopes. While RGGI is a carbon pricing regime that is tightly focused on the electricity sector within a multi-state region of the United States other carbon pricing mechanisms have dramatically different geographic and economic scopes. These alternative program scopes are important to consider in the context of the policy goals for any carbon pricing mechanism.

Specifically, both California and the European Union (EU) operate robust cap-and-trade programs with scopes quite different from RGGI. The California program is largely a single-state program, though it is linked with the Canadian province of Quebec. The EU program is a multinational program within the EU and also has links outside of the EU. Furthermore, an additional carbon pricing mechanism, a national carbon tax, is deployed by some nations in combination with the EU cap-and-trade program.

The following subsections discuss key details regarding the scope and operations of these programs.

3.4.1. California

California operates a cap-and-trade program in partnership with Quebec. Although the program is designed to link with other similar programs through the Western Climate Initiative, no additional linkages have been established to-date. This program has a broad economic scope and, despite covering a single U.S. state, also has a fairly broad geographic footprint due to California's size and the diversity of climate conditions across the state.

Economically, the program covers a broad range of economic sectors including electric generation, large industrial plants, and distributors of transportation and other fuels. (California Air Resources Board 2015) Electric generators and industrial facilities emitting 25,000 metric tons of carbon dioxide equivalent or more annually are required to participate by obtaining emission allowances through the program. (California Air Resources Board 2015) Altogether California's cap-and-trade program covers approximately 85 percent of the state's emissions, including electricity generation from other states. (California Air Resources Board 2015)

This combination of geographic, economic, and environmental scope makes California's cap-and-trade program quite different from the RGGI. It is difficult, therefore, to directly compare the programs with regard to their emission allowance prices and impacts. Furthermore, California has significant general climate differences compared with the RGGI member states that are important. Specifically, California has a mix of relatively mild coastal weather year-round combined with extreme heat in inland areas as well as both summer heat and winter cold in the mountains.

Climate differences may result in different energy and emissions intensity for certain activities such as building heating and cooling. Similarly, economic differences may mean that one state or region has a more emissions-intensive economy than another. A well-designed emission cap and baseline should be able to account for such differences in terms of designing a carbon pricing mechanism and evaluating outcomes. However, such differences may also make it more difficult for one state or region to achieve a certain percentage of emission reduction due to a need for relatively more costly investments or technological improvements.

Nonetheless, California's cap-and-trade program experience provides information that can be useful to Illinois policymakers. First, in the context of California's program, FERC has authorized border adjustments of electricity prices for electricity delivered into California from other states through the Western Energy Imbalance Market. (California Independent System Operator Corporation, 165 F.E.R.C. ¶ 61,050 2018) Thus, there is a clear precedent from federal energy regulators for allowing states to address the potential for emissions leakage by ensuring that state cap-and-trade compliance costs are incorporated in the price of electricity generated in other, non-participating states. This is important for California's program due to the fact that the state is isolated from its neighbors in operating a stand-alone carbon market while its power market is well-connected with the surrounding states, allowing for the risk of emission leakage due to electricity imports from these other states.

California also highlights issues with respect to program effectiveness and impacts on the electricity sector. Importantly, the impact of that program on the electricity sector's carbon emission reductions is inconclusive and it remains an open question whether it has had an impact that is incremental to other state energy policies. More specifically, a January 2020 California Legislative Analyst's Office (LAO) report found that the state's electricity sector has been the primary driver of greenhouse gas emission reductions. (Petek 2020) However, the state RPS program is likely to have been a substantial driver of emission reductions while the electric sector emission reductions due to the cap-and-trade program are unclear. (Petek 2020)

Of course, this program extends well beyond the electricity sector alone, and therefore it would not be appropriate to conclude that the program does not work to reduce emissions as a result of these findings. Instead, the LAO's conclusions simply highlight that the precise impact of this program is uncertain. Even if the carbon price itself does not drive the majority of emission reductions in the state, for example, electric utilities use revenue from the cap-and-trade program to offer customers bill credits. (Petek 2020) If these bill credits, in turn, cost increases related to the RPS program and other emission reduction measures, they may be critical to the implementation of these other policies.

3.4.2. European Union

Like California's cap-and-trade program, the EU's Emission Trading System (ETS) has a broad economic and geographic scope. The EU's program also has the additional complexity of linking many different nations both within and external to the EU's borders: The EU ETS operates in the EU's 27 member states as well as the countries of Iceland, Liechtenstein, and Norway, and is also linked to Switzerland's separate carbon market. (European Commission 2020) The EU program covers electricity generation, a variety of industrial facilities, and aviation emissions for flights within the European Economic Area (EEA). (European Commission 2020) Moreover, the EU program may expand its coverage of aviation to include all flights leaving and entering the EEA beginning in 2024. (European Commission 2020) Overall, the EU ETS covers approximately 38 percent of total EU greenhouse gas emissions. (European Commission 2020)

Also similar to California, it is difficult to directly compare the program EU ETS with RGGI due to their different scopes. The broad geographic scope and range of nations of the EU ETS also indicates that general climate differences with RGGI could be relevant. Given that the EU ETS ranges from relatively warm Mediterranean countries to the colder Scandinavian countries in the far north, it is reasonable to expect that the EU ETS includes a greater diversity of climates and related emissions compared with the RGGI states. As with California, these differences may be associated with differences in the emissions intensity of society and the relatively difficulty and cost of achieving a certain level of emission reduction.

Another important characteristic of the EU ETS is that it covers a large geographic area where each contiguous nation either participates in the program or has a separate carbon market that is linked with the program. Thus, there is relatively little risk of emission leakage except at the outer borders of the EU and other participating countries. This is quite different from the situation in RGGI, where a number of member states participate in the PJM wholesale electricity market alongside neighboring states who are not RGGI members.

Analysis of the outcomes driven by the EU ETS is complicated by the adoption of national-level carbon taxes in addition to the ETS (The World Bank 2020) as well as substantial national energy policy programs such as Germany's Energiewende. (International Energy Agency 2020) Like California, however, the emission reductions caused by the EU ETS are inconclusive. One recent study found that the program resulted in an estimated emission reduction of about 3.8 percent between 2008 and 2016 despite a prolonged period of low emission allowance prices. (Bayer and Aklin 2020) Although the estimated emission reduction is not large, it is worthwhile to note that this occurred at very low allowance price levels and amounted to almost half of the EU's promised emission reductions under the Kyoto Protocol. (Bayer and Aklin 2020) Thus, program refinements that result in more stringent allowance caps and higher prices could produce larger reductions in later years. Furthermore, while this study was published by a respected source, it does not necessarily represent a definitive conclusion regarding the effects of the EU ETS.

3.5. KEY TAKEAWAYS AND LESSONS LEARNED FROM THE CASE STUDIES

3.5.1. Key Takeaways from New York, New Jersey, and Virginia Case Studies

Table 3 briefly summarizes three key takeaways from the foregoing case studies of RGGI states. Each of these takeaways is summarized in more detail below.

Table 3: Key Takeaways from State Case Studies

Key Takeaways	Relevant Case Studies
Consensus from the legislature and executive is crucial	New Jersey, New York, Virginia
Make good use of the auction proceeds	New Jersey, New York
Don't take RGGI as everything for your state climate policy	New Jersey, New York, Virginia

Firstly, consensus from the legislature and executive is crucial. It is critically important that the executive and legislature of the state need to establish a certain level of consensus in the state's climate policy stance. We have seen cases for many times where the dissent from either part hindered the progress of joining RGGI, such as New Jersey's withdrawal in 2011 and Pennsylvania's hesitation to join in 2020. Virginia's process of joining RGGI was also postponed by its legislative body, the General Assembly, by including a prohibitive provision in the state budget in 2019. In New York, however, the legislature and the executive have been working together to ensure its success in RGGI, which was confirmed and praised by a NY Department of Public Service personnel via interview.

Secondly, it is beneficiary for the RGGI states to make good use of the auction proceeds. As portrayed above, the proper use of auction proceeds in energy efficiency, clean energy and environmental justice fields have contributed greatly in the success of New York in RGGI implementation. In contrast, states such as New Hampshire simply used its share of the proceeds in balancing the state bills. In New Hampshire, over 77% percent of 2018 proceeds and over 54% of total proceeds went to direct customer rebates[4]. Similarly, New Jersey also directed all of its auction proceeds towards state budget balancing in 2010 and 2011. The state improved its spending strategy greatly after rejoining, as depicted in the case study above. The difference made by proceeds investment can be enormous, notwithstanding the current void of quantitative analysis on these impacts.

Thirdly, don't take RGGI as everything for the state climate policy. After joining RGGI, New York has worked hard in setting more ambitious climate goals, and also in developing state-level policies that work together with RGGI. The CLCPA and the "carbon adder" policy are proof that New York didn't treat their success in RGGI as their ultimate objective in combating climate change. While having decided to join RGGI, Virginia launched the Clean Economy Act and the Commonwealth Energy Policy in 2020 that set progressive GHG emission and clean energy goals. New Jersey also launched the Global Warming Response Act, which aims for 80% GHG reductions from 2006 level by 2050 and has numerous initiatives targeted at the transportation sector. If Illinois joins RGGI in the future, regardless of how it works, it would still be great if Illinois can take the initiative and work proactively to seek climate actions beyond RGGI, which might probably create more benefit in emissions reduction renewable energy development, and also for a broader sense of public good.

3.5.2. Key Takeaways from CA and EU Cases

There are three key takeaways from the experiences of California and the EU for states evaluating potential carbon pricing mechanisms. First, cap-and-trade programs can vary in scope and the scope of a program can change over time. These variations in scope have important implications for the complexity and implementation of the program.

Second, evidence of emission reductions specifically due to these cap-and-trade programs is inconclusive as they are paired with other complementary policy measures. Emissions do appear to decrease due in part to policy measures, but attributing emission decreases to carbon pricing with certainty is difficult. Furthermore, as California illustrates, it is possible that cap-and-trade programs are important in conjunction with complementary policies even if a carbon price is not directly responsible for emission reductions.

Finally, federal regulators in the United States have already approved a border adjustment with respect to electricity imported from states without a carbon price into a state with a carbon price. This indicates that border adjustments may indeed be a viable policy options for states going forward.

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[4] RGGI 2018 Investment Proceeds Report, https://www.rggi.org/sites/default/files/Uploads/Proceeds/RGGI_Proceeds_Report_2018.pdf

4. MARKET ANALYSIS AND PRICE IMPACTS

4.1. INTRODUCTION

Any carbon price scheme, including but not limited to a RGGI-style cap-and-trade approach, is going to impact electricity markets. At a high level, it is reasonable to expect that a carbon price would increase the price of power from coal and gas-fired generators, potentially pricing some of them out of the energy market. Consequently, such a policy might be expected to affect wholesale prices and CO_2 emissions as well. However, with numerous factors to consider, from the specific price impact for each generator based on heat rate and carbon intensity, to the potential for emissions leakage from neighboring states, these outcomes can be challenging to forecast precisely.

The following section explores how carbon pricing schemes impact wholesale electricity prices, generation by fuel source, and CO_2 emissions — both in Illinois and for the rest of PJM.

To provide some relevant background knowledge to set the backdrop for the model results, an overview of the electricity profiles for each state is provided to illustrate key similarities and differences between Illinois and existing RGGI states. Additionally, an illustrative analysis for coal-fired and natural gas-fired generators under a range of assumptions provides a useful approximation of price impacts and illustrates the potential magnitude and range of electricity price impacts.

These discussions provide useful framing for the modelled outcomes discussed in this section. While this report does not present novel market modeling results, it provides analysis of the modeling results provided by PJM itself as well as by independent consultants. In particular, the PJM model results — the product of a two year investigation by the organization's Carbon Pricing Senior Task Force (CPSTF) — provides a preliminary look at impact of RGGI membership among several combinations of PJM states, including one scenario that includes Illinois. As discussed in detail in the context of this analysis, these modeling efforts provide estimates of the changes to the generation mix, carbon emissions, and wholesale prices at the state/zone level, taking into account the broader dynamics of the PJM energy markets. These results offer a glimpse of what the power sector in Illinois might look like after joining RGGI. The PJM study has several limitations which will be discussed in detail, yet it provides initial estimates that can help guide future research.

Finally, it is important to consider potential electricity price impacts in the context of clean energy project developers and owners along with retail customers. It is difficult to provide precise estimates of how the potential electricity price impacts of carbon pricing relate to clean energy projects and retail customers based on publicly available information. Nonetheless, this section concludes with a discussion of these impacts given information that is readily available.

4.2. STATE ELECTRICITY GENERATION SOURCES AND THE POTENTIAL FOR EMISSION LEAKAGE

The state-by-state electric generation mix detailed in Table 4 provides 1) an overview of the different generation sources that states use, and 2) the total retail electricity sales within each state as a percentage of total electricity generation within that state. For the purposes of this report, the focus is primarily on midwestern states and the specific RGGI states that were analyzed in the case studies. Data from other states is available from the U.S. Energy Information Administration (EIA). The data in the Table 4 illustrates the potential for emissions leakage should Illinois adopt a carbon pricing mechanism. (U.S. Energy Information Administration 2021) Nearby PJM member states as well as MISO member states have fossil fuel-dependent generation mixes that are not subject to a carbon price. However, many of these states are also net importers of electricity.

Table 4: Electricity Demand and Generation of Selected States, 2019

State	Total Retail Sales as % of Total Generation GWh	Generation (%)					
		Total	Coal	Gas	Nuclear	Renewables	Other
IL	75%	100%	26%	12%	54%	8%	1%
IA	81%	100%	35%	12%	8%	43%	1%
IN	100%	100%	59%	31%	0%	7%	3%
OH	124%	100%	39%	43%	14%	2%	2%
MI	87%	100%	32%	30%	28%	7%	4%
WI	110%	100%	42%	32%	16%	7%	2%
KY	105%	100%	72%	21%	0%	6%	1%
MO	101%	100%	71%	10%	12%	7%	1%
CA	124%	100%	0%	43%	8%	40%	9%
NY	111%	100%	0%	36%	34%	27%	2%
NJ	104%	100%	1%	57%	38%	2%	2%
VA	122%	100%	4%	60%	30%	3%	4%

	Net Importer
	Net Exporter

In 2019, the states under carbon pricing programs, California, New York, New Jersey, and Virginia, had little to no generation from coal plants, but had on average a higher percentage of generation from natural gas plants than the midwestern states. Notwithstanding Illinois, carbon pricing states also had a higher percentage of nuclear generation than the midwestern states. The results, however, were mixed when generation from renewables were compared across the listed states, given the lower share of renewables in New Jersey and Virginia and the higher share of wind power in Iowa. Ultimately, Table 4 suggests that electric power in the carbon pricing states is relatively cleaner than in the Midwest. It is worth noting though that the difference is not a reflection of a causal relationship associated with carbon pricing, but rather that there is a significant correlation in those states.

In addition, the demand for electricity of the listed states provides a preliminary indication of the potential for emissions leakage. Demand in the listed carbon pricing states in 2019 exceeded the total generation within the states. In other words, they were net electricity importers. Whereas, Illinois was a net exporter in 2019. If Illinois was to introduce a carbon pricing mechanism, its thermal generation would become more expensive. As a net exporter, some of these costs would be incurred by the importing states if a border adjustment rule was established to avoid carbon leakage. Iowa, Indiana, and Michigan were also net exporters, but with a larger share of electric generation coming from coal and natural gas than cleaner resources. As such, the level of carbon dioxide emissions reductions in the region could potentially be impacted if Illinois were to adopt a carbon pricing mechanism. The impacts would partially depend on how the other net importer states in the Midwest meet their excess demand (e.g., if they decide to import more electricity from other non-carbon pricing, net exporter states).

Thus, as a result of the nuances between the states, as well as the aggregated nature of this data, it is difficult to establish precisely how electricity is transferred between these states. Nonetheless, the diversity of generation resources mixes in Illinois' neighboring states highlights that carbon pricing in Illinois may carry unintended consequences vis-à-vis the generation fleets of other states.

4.3. ILLUSTRATIVE CARBON PRICE IMPACT BY GENERATION TYPE

Carbon price impacts on the unit cost of different generator types can provide an indication of the impact carbon pricing will have on wholesale electricity prices. Generally speaking, wholesale energy prices reflect the unit cost of the most expensive generation resource that the market operator must dispatch to meet energy demand, otherwise known as the marginal unit. The marginal unit varies during the course of each day, month, and year as well as among different locations.

The impact of a carbon price on the unit cost of the market's average marginal unit, therefore, offers an illustrative proxy for the impact of a carbon price on average market electricity prices. The key characteristics of the marginal unit are the fuel type and efficiency. Coal is in general a more emission-intensive fuel source than natural gas, and generation units with higher efficiency generally produce fewer emissions per unit of electricity generated. Zero-emission resources, of course, would have zero carbon price-related impact on wholesale electricity prices.

Given the prevalence of natural gas- and coal-fired generation in the resource mix among PJM member states, it is reasonable to expect that the marginal unit is often a natural gas or coal generator. Several types of natural gas generation technologies exist in the market and it is therefore prudent to assess those that employ a steam boiler, combustion turbine, and a combination thereof (i.e., a combined cycle) based on reasonable efficiency data.

Table 5 presents heat rate assumptions for each of these generator types. Generator heat rates are simply the thermal content of fuel required per unit of electricity, in this case British Thermal Units of fuel consumed per kilowatt-hour of electricity produced. The heat rate for most of the generator types listed, labeled “EIA Avg,” are based on 2009 through 2019 average plant type data from the U.S. EIA’s Form EIA-860 Electric Generator Report. (U.S. Energy Information Administration n.d.) The table also presents additional sensitivity cases based on natural gas combined cycle generators at different efficiency levels. The first corresponds to the low cost case heat rate assumed in Lazard’s Version 14.0 Levelized Cost of Energy Analysis. (Lazard 2020) The second corresponds to the maximum nameplate heat rate for a new General Electric GE 9F.05 combined cycle unit. (GE Power 2019)

Table 5: Heat Rate Assumptions by Generator Type

Generator Type	Heat Rate (btu/kWh)
Coal (EIA Avg)	10,002
Natural Gas Steam Generator (EIA Avg)	10,347
Natural Gas Combustion Turbine (EIA Avg)	11,098
Natural Gas CCGT (EIA Avg)	7,633
Natural Gas CCGT (Lazard Low)	6,900
Natural Gas CCGT (GE 9F.05 Nameplate)	5,619

Figure 16 shows the potential electricity price increase associated with emission allowance prices of $6.87 per short ton and $14.88 per short ton. These carbon prices are consistent with the RGGI carbon price scenarios modeled by PJM and discussed in detail in the subsequent section. These results show a range of potential electricity price impacts. The lower end of this price impact range corresponds to the maximum efficiency level of a new natural gas combined cycle generator while the higher end corresponds to a coal generator. Average natural gas combined cycle, natural gas steam generator, and combustion turbine generators fall in between these levels.

Figure 16: Estimated Carbon Price Impact on Electricity Price by Generator Fuel and Technology Type

These wholesale price impacts are merely illustrative. However, they are generally indicative of the magnitude of potential carbon price impacts if the market is not able to shift in favor of less emission intensive resources that result in a smaller price increase. If a coal plant is cheaper to dispatch than a combined cycle with no carbon price adder, it is possible that after implementing a carbon price an otherwise relatively expensive combined cycle could be dispatched instead of a coal plant. This shift from one resource to another could partially mitigate the wholesale electricity price impact.

For example, using these illustrative price impacts, at a carbon price of $6.87 per short ton, a combined cycle natural gas plant has a carbon cost per megawatt-hour that is about $4 less than that of a coal plant ($7.15/MWh vs. $2.26-$3.06/MWh). If dispatching the combined cycle would cost $2 per MWh more than dispatching the coal plant absent a carbon price, the combined cycle will be less expensive than the coal plant net of the carbon price and this will partially mitigate the market price impact.

Thus, these estimated electricity price impacts do not represent the full impact of market dynamics but rather indicate a reasonable range of potential impacts. This underscores the need for more comprehensive modeling of the PJM market to more precisely understand the wholesale electricity price impact of carbon pricing.

4.4. PJM CARBON PRICE MODELING

4.4.1. PJM Modeling Background

As discussed in Section 2.2.2, PJM spent 18 months studying and modeling the impacts of potential carbon prices and leakage mitigation mechanisms in the RTO's wholesale electricity markets. Numerous scenarios were considered, with characteristics ranging from the composition of the carbon pricing sub region (i.e., the states with a carbon price) to the price of carbon, to the type of border adjustment. These scenarios were modeled using Energy Exemplar's PLEXOS Integrated Energy Model, and the final results provided a glimpse of the possible effects of a carbon price to generation, prices, and emissions. Several combinations of states were considered for the carbon price sub region, including, fortunately, one scenario which assumes Illinois would impose a price on carbon along with Delaware, Maryland, New Jersey, Virginia, and Pennsylvania. Given that all the aforementioned states except for Pennsylvania have joined RGGI and Pennsylvania itself is moving rapidly towards joining the program, this scenario is quite plausible. For the purpose of this discussion, this section will focus on the scenario that includes Illinois, covering the $6.87/ton and $14.88/ton scenarios. Given that there are no current border adjustment policies in place anywhere in PJM or RGGI, this section will primarily focus on the "no border adjustment" scenarios, though a discussion of the impact of one-way and two-way border adjustments is included as well.

Figure 17: PJM Carbon Price Modeling Scenarios

Carbon Price Sub-Region	Carbon Price	Border Adjustment
None	$6.87/ton	None
DE MD NJ VA	$14.88/ton	One-Way
DE MD NJ PA VA	$25.00/ton*	Two-Way
DE MD NJ PA	$50.00/ton*	
DE MD NJ PA VA IL		
Entire RTO	*not used for every sub-region scenario	

The primary limitation of the PJM model is that it only provides a snapshot of the outcomes resulting from carbon price participation; the model results only cover generation, prices, etc. for the year 2023.

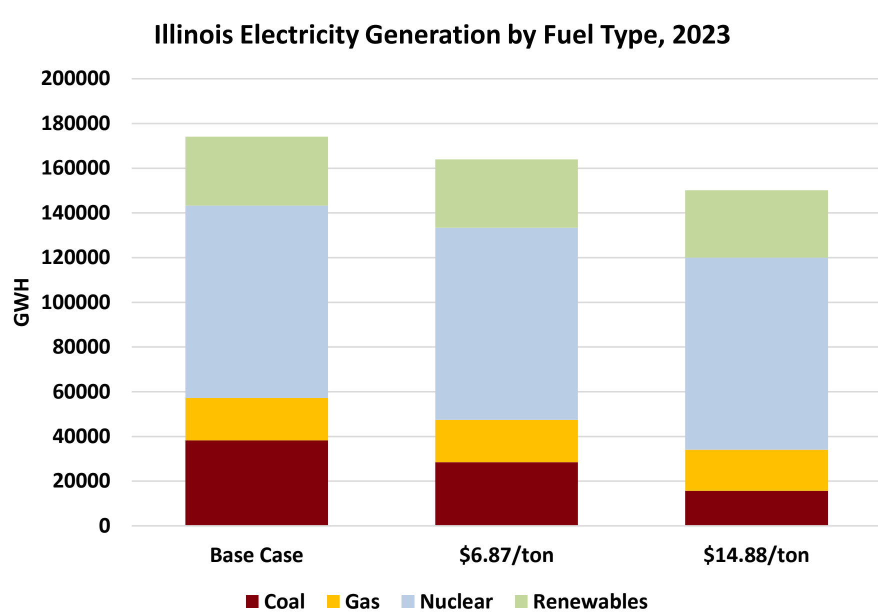
This makes it difficult to establish long-term trends and moreover, given how close 2023 is from the present, the modeled outcomes may not fully capture the impact to any new powerplants that would be built in the wake of Illinois — or any of the states that have just recently or are the in process of joining RGGI — adopting a cap-and-trade program. Still, this single snapshot provides a glimpse of the near-term effects of Illinois' entry into the program, and — as will be discussed in detail in this section — show the strong potential for reduced emissions in the state as a result of such action.

Note that the raw data used in this analysis (including numerous other scenarios not discussed in this report), as well as PJM's own discussions about assumptions and outcomes, can be found here: https://www.pjm.com/committees-and-groups/task-forces/cpstf.

4.4.2. Generation Mix

The most noticeable impact of Illinois' participation in a carbon price sub-region will be a dramatic reduction of power generation sourced from coal. Assuming $6.87/ton carbon prices and no border adjustment — the conditions closest to present day realities — Illinois could reduce its coal-fired generation by 25% in 2023, compared to the coal-fired generation that would occur if Illinois elected not to impose a carbon price. Specifically, PJM projects 38,252 GWh of coal-fired generation in Illinois in 2023 in the business-as-usual scenario, and 28,471 GWh in the $6.87/ton carbon price one. If the price of carbon were to rise to $14.88/ton, coal-fired generation would further decrease to 15,649 GWh — a reduction of nearly 60% compared to business-as-usual.

Figure 18: Illinois Generation by Fuel Type Under PJM Carbon Price Modeling Scenarios (No Border Adjustment)



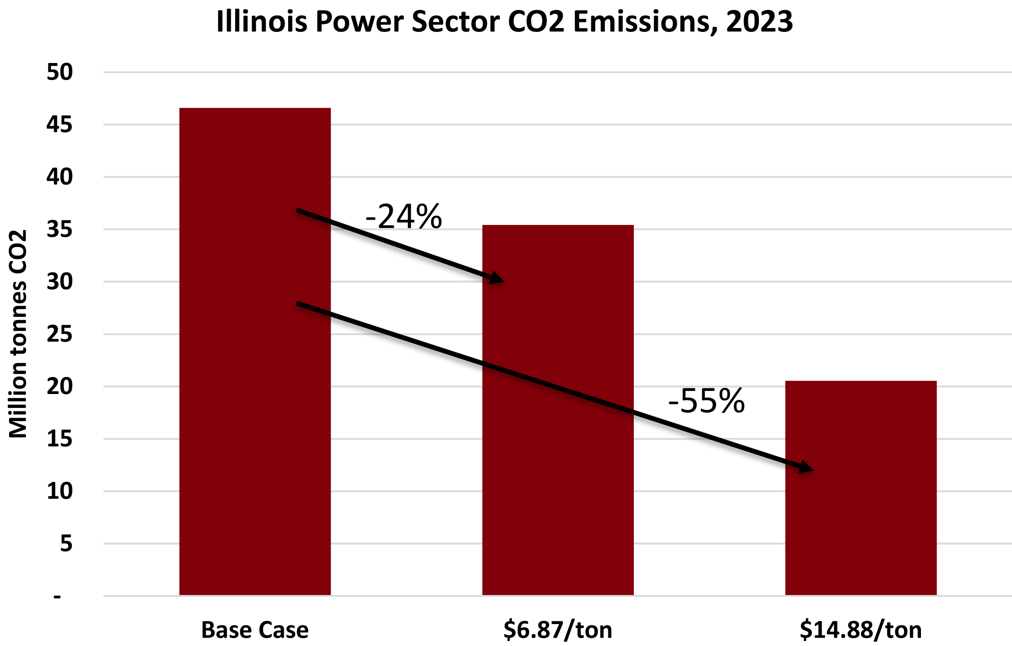
It is worth noting that under both the \$6.87/ton and \$14.88/ton scenarios, total generation in Illinois decreases by roughly the same amount as the losses from coal. That is, the decreases in coal-fired generation are not replaced with additional gas, nuclear, wind, etc. According to the PJM model assumptions, part of this will be addressed by distributed energy resources, but the model itself does not project the exact amount of off-grid solar in any scenario. Unfortunately, at least some of the lost generation will be replaced by increased generation — specifically, from coal — from nearby states. The model does not specify cross-border flows, so it is difficult to ascertain how much of the increased coal-fired generation from Indiana, Ohio, and West Virginia (+12,022 GWh and +20,968 GWh in the \$6.87/ton and \$14.88/ton, no border adjustment scenarios, respectively) will flow to Illinois — likely a great deal of it will go to Pennsylvania, which will also substantially reduce its own in-state coal-fired generation after joining RGGI. However, it is reasonable to assume that a not-insignificant amount of emissions leakage will take place.

Overall, RTO-wide, coal-fired generation decreases 14% in the \$6.87/ton scenario and 23% in the \$14.88/ton one. So while some states may burn additional coal in the aftermath of Illinois and Pennsylvania (the states in the carbon-price sub region with the highest use of coal in their current generation mix) joining RGGI, the RTO as a whole still reduces its reliance on coal.

4.4.3. Emissions

As might be expected, the substantial reduction in coal-fired generation in Illinois — and across the whole RTO — will lead to a dramatic decrease in carbon emissions as well. Under the business-as-usual scenario, the state of Illinois will emit 46.5 million tons of CO_2 related to electricity generation in 2023; under the \$6.87/ton scenario, this number falls to 35.4 million tons — a drop of 24%. And in the \$14.88/ton, carbon emissions are just 20.5 million — a 55% reduction compared to business-as-usual.

Figure 19: : Illinois Power Sector Emissions Under PJM Carbon Price Modeling Scenarios (No Border Adjustment)



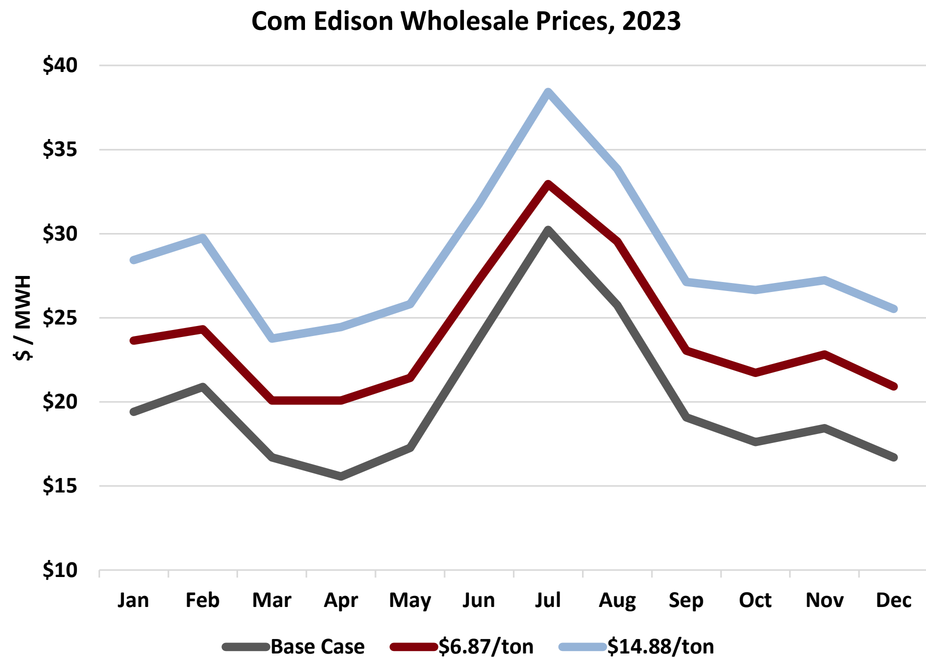
Despite the emissions leakage issues discussed earlier, RTO-wide emissions decrease noticeably as well. Under the $6.87/ton and $14.88/ton scenarios, emissions will be 8% and 14% lower (respectively) compared to business-as-usual.

4.4.4. Prices

The decline in coal-fired generation and related emissions comes at a cost to the ratepayer. PJM does not specify how much of the price increases are driven by the cost of transitioning away from coal, and how much is related to the cost of compliance. In total, participation in a carbon price sub region — at a carbon price of $6.87/ton — will result in a $3.87/MWh increase in the average annual cost of electricity compared to business-as-usual; that is, an increase from $20.12/MWh to $23.99/MWh. At $14.88/ton, the price of electricity becomes $28.57 — an $8.45/MWh increase compared to business-as-usual.

It is worth noting that in carbon price states that have already replaced most of their coal-fired generation with natural gas or renewables (e.g., Maryland and New Jersey), the price impact is much more muted, generally around ~$1-1.50/MWh in the $6.87/ton scenario and $4-5/MWh in the $14.88/ton scenario. On the other hand, these states also experience a substantially reduced impact to emissions related to joining the carbon-price sub region; in short, the effect of the cap-and-trade policy is simply reduced across the board for states that do not rely heavily on coal.

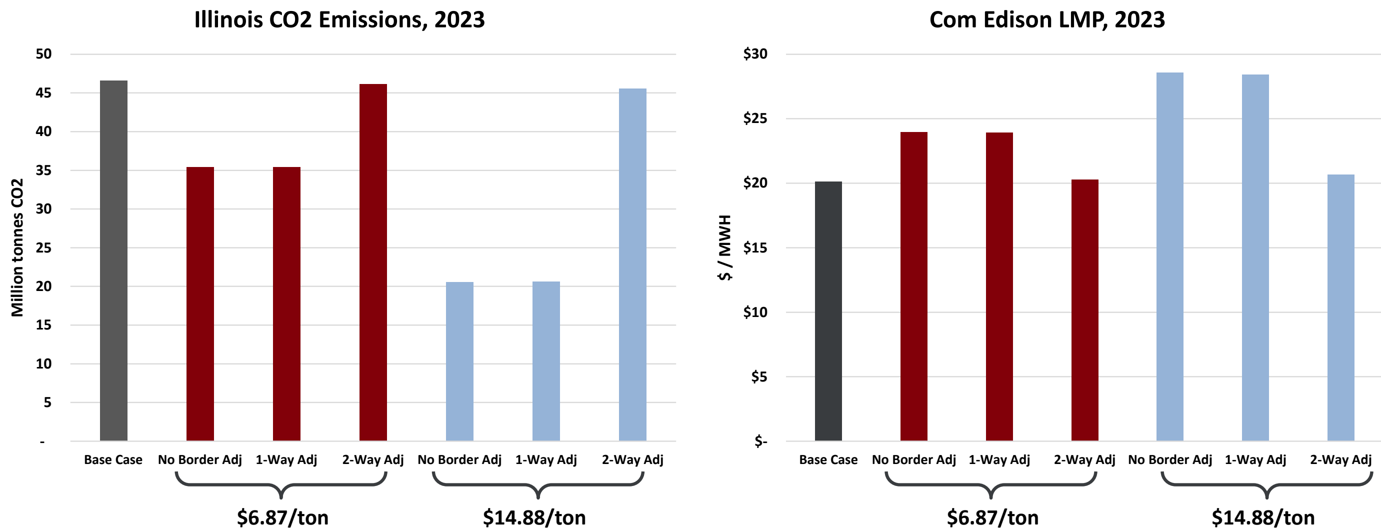
Figure 20:Commonwealth Edison Zone Locational Marginal Prices Under PJM Carbon Price Modeling Scenarios (No Border Adjustment)



4.4.5. Border Adjustment

The introduction of border adjustment to these scenarios can hugely alter the outcomes related to participation in the carbon-price sub region, substantially affecting all aspects of the modeled results. In the scenarios covered in this section — including a Delaware, Illinois, Maryland, New Jersey, Pennsylvania, and Virginia carbon price sub region and either $6.87/ton or $14.88/ton carbon prices, a border adjustment can potentially do very little at all, or entirely reverse the changes brought about by joining the carbon price sub region. Specifically, a one-way border adjustment results in very little change to generation, emissions, or prices beyond what is already achieved in a no border adjustment scenario — the two are practically identical. On the other hand, a two-way border adjustment almost entirely reverses these changes, resulting in levels of coal-fired generation that are nearly identical to the business-as-usual scenario, with similarly identical emissions and prices. In effect, if a two-way border adjustment were implemented across PJM, it would almost entirely eliminate both the positive and negative effects of states joining a carbon price sub region. It would be as if none of the states imposed a carbon price in the first place.

Figure 21: Illinois Power Sector Emissions and Commonwealth Edison Zone Locational Marginal Prices Under PJM Carbon Price Modeling Scenarios (Including Border Adjustments)



4.4.6. Model Limitations

While PJM’s study provides a valuable glimpse at the potential near-term impact of a cap-and-trade program on Illinois as well as the rest of the RTO, there are several limitations to the model. As mentioned earlier, the model only provides a single snapshot of the year 2023, which limits its utility in gauging long-term effects. Moreover, the model doesn't specify changes in demand, energy efficiency, cross border flows (imports/exports), and offgrid solar, resulting in an incomplete picture of the full range of changes that will occur to the electricity sector. Additionally, while PJM does not provide the exact assumptions for generators by fuel source (market heat rate, break-even prices, etc.), it is reasonable to assume that these may be rough estimations across the entire RTO. For future studies pertaining to Illinois specifically, it may of added benefit to tailor these assumptions to generators in Illinois.

4.5. ENERGY AND ENVIRONMENTAL ECONOMICS (E3) STUDY OF CARBON PRICING IN THE PJM MARKET

Separate from PJM’s modeling of its market under different carbon price scenarios, the consulting firm E3 examined several policy scenarios to drive GHG emission reductions within the PJM market area. On balance, E3’s analysis finds that carbon pricing can be a highly efficient mechanism for driving emission reductions, but that emission leakage is highly problematic when only a subset of PJM member states adopts a carbon price.

The E3 study focuses on different policy alternatives for the PJM market area rather than granular analysis of carbon pricing specifically. As a result, it does not offer results specific to the state of Illinois, but it does offer broad takeaways regarding the usefulness of a carbon pricing mechanism. E3's report argues that '[t]he region's current carbon pricing mechanism, the RGGI, does not apply to the entire PJM footprint. Much of the PJM system's coal capacity is located in states that are not part of RGGI. The principal effect of this partial carbon pricing program, as modeled by E3, is reduced natural gas generation in states with carbon pricing and increased coal generation in states without carbon pricing." (Energy and Environmental Economics 2020) However, one of E3's scenarios analyzes a system-wide PJM carbon price to the existing policy environment, effectively extending RGGI to all PJM member states.

This PJM system-wide carbon price scenario results in a relatively efficient reduction in GHG emissions. In this scenario, the PJM states achieve more than 100 million tons in incremental emission reductions by 2030 compared with a similar, business-as-usual scenario incorporating a carbon price for the current RGGI states only. (Energy and Environmental Economics 2020) Moreover, these emission reductions incur annual cost increases that are *less* than in the business-as-usual scenario. The main difference in energy generation portfolios between these scenarios is the elimination of coal generation and a modest increase in nuclear generation. The importance of eliminating coal in the system-wide carbon price scenario underscores the importance of eliminating emission leakage in E3's model. (Energy and Environmental Economics 2020)

Finally, the E3 study notes the danger that emission leakage could undermine the positive impact of a carbon price. On this issue, E3 concludes:

> A carbon price is clearly an effective policy for achieving carbon reductions but has counterintuitive effects when only applied to a portion of the PJM states. The issue of emissions leakage under RGGI has been studied extensively over the past several years. Recent modeling by PJM has tested the implications of wider RGGI coverage and/or border adjustment mechanisms to mitigate emissions shuffling to resources outside of RGGI. PJM's modeling of this issue in PLEXOS differs greatly from E3's approach: PJM uses a more granular production-cost model focused on near-term implications, whereas E3's model is a higher-level approach to capture broad, longer-term impacts. However, both studies have yielded similar findings that suggest wider coverage by RGGI will help mitigate current leakage issues. (Energy and Environmental Economics 2020)

Thus, E3's study confirms the importance of preventing or mitigating emission leakage. Subject to this condition, carbon pricing may be a cost-efficient way to reduce electric sector emissions. However, since E3's analysis reflects a PJM-wide carbon price, this result cannot necessarily be extrapolated to RGGI participation by a subset of PJM member states or an independent Illinois carbon price.

4.6. CARBON PRICE IMPACTS ON CLEAN ENERGY PROJECTS AND RETAIL CUSTOMERS

Although the PJM energy price impacts of implementing a carbon price in Illinois are important in their own right, it is also important to consider their impact on Illinois stakeholders in the context of other policy issues. FERC has put forth carbon pricing as a technology-neutral alternative to state clean energy policies such as RPS programs. At the same time, PJM, with FERC's endorsement, has implemented the MOPR in its capacity market, thereby reducing or eliminating the capacity market revenue that clean energy projects receive. Therefore, it is important to consider the impact of carbon pricing on clean energy projects and retail consumers alongside the impact of the MOPR on the capacity market.

If the MOPR were to result in a situation where clean energy projects could no longer benefit from capacity market revenue, it is possible that the net effect of carbon pricing alongside the MOPR on clean energy projects would be neutral. That is, clean energy projects would receive approximately the same total revenue from PJM's markets as they would have without the MOPR and carbon price. At the same time, this situation could result in a net increase in costs to retail customers if the MOPR is cost-neutral or cost-increasing overall. In that case, retail customers would continue to pay the same or higher capacity costs as part of their bills while also paying higher energy costs due to the carbon price, assuming that retail suppliers pass through wholesale supply costs in full to customers.

Thus, the MOPR and RGGI's carbon pricing mechanism have not been designed to be offsetting policies and it is possible that they could have different impacts on clean energy projects and retail customers. The report sections below discuss the potential impacts on clean energy projects and retail customers in greater detail.

4.6.1. Clean Energy Project Impact

PJM's MOPR could impact clean energy projects by forcing them to forego revenue from PJM's capacity market. At the technology specific minimum offer prices imposed by the MOPR, wind and solar projects may not be able to clear future auctions. A carbon price would impact clean energy projects by increasing their revenue from PJM's energy market: A carbon price increases operating costs for fossil fuel generators, thereby increasing PJM's energy market prices. These higher energy market prices would, in turn, increase net market revenue for clean energy generators since emission-free resources would not have any compliance costs associated with the carbon price but receive the resulting higher energy market price in all hours when thermal units set the price. Therefore, the net impact of the MOPR and a carbon pricing mechanism on clean energy projects depends on their expected capacity market revenue lost and expected energy market revenue gained.

A range of publicly available estimates exist as to the effect of the MOPR on a dollar per MWh basis. Industry consultants and renewable energy developers have put forth public estimates of this value, which are summarized in the table below. These estimates provide useful benchmarks but may not be reflective of the full range of capacity market impacts on generators, particularly with respect to existing nuclear plants. The estimates are provided by Grid Strategies LLC (Goggin and Gramlich 2020), Apex Clean Energy (Kowalski 2020), and Edison Energy (Li 2020)**.**

Table 6: Estimated Renewable Energy Project $ per MWh Price Impact of PJM MOPR

Carbon Price Sub-Region	Low Estimate ($/MWh)	High Estimate ($/MWh)
Grid Strategies Report	$1.90 (wind)	$14.58 (solar)
Apex Clean Energy, via Energy News Network	$3.00 (wind) / $5.00 (solar)	$7.00 (wind) / $9.00 (solar)
Edison Energy	$3.00 (solar)	

These estimates of the impact from lost capacity market revenue broadly align with the estimated PJM energy market price impacts for Illinois, as well as the illustrative range of impacts for fossil fuel generator types. As discussed in more detail in Section 4.4.4, PJM's modeling of a carbon price subregion within its market shows that adopting a carbon price in Illinois could result in energy prices that are $3.87 per MWh to $8.45 per MWh higher than in a scenario where Illinois does not participate. Given the similar magnitude of estimated revenue per MWh impacts, it is possible that incremental energy market revenue due to the implementation of a carbon price could approximately offset the lost capacity market revenue due to the MOPR.

Given that the policies are not linked, it is possible that the energy market impact of carbon pricing could be $3 per MWh while a clean energy project's lost capacity market revenue due to MOPR is $7 per MWh or more. In this case, solar and/or wind project developers in Illinois would be net worse off after PJM implemented MOPR and the state implemented a carbon price.

It is also important to note that there are additional nuances to the energy market revenue that wind and solar projects can actually receive since energy prices will vary throughout the course of each day, month, and year. In addition, wind and solar generators will likely not produce electricity at exactly the same times and therefore will earn different amounts of revenue for each unit of electricity generated. Moreover, nuclear generators, due to their around the clock operating profile, may experience both different results due to PJM's MOPR and different energy market revenues than wind and solar generators.

As a result, it is difficult to confidently conclude whether adoption of a carbon price would fully offset the impact of PJM's MOPR for clean energy developers in Illinois. It is fair to say that the magnitude of the MOPR's impact is generally consistent with the potential impact of a carbon price. As discussed in

However, Illinois would need to conduct a detailed analysis of both the impact of MOPR on clean energy projects of different technology types and of specific carbon pricing proposals for the state of Illinois on wholesale electricity prices. Moreover, it may be helpful for the State of Illinois itself to conduct and/or commission these studies so that it can define the specific parameters of each analysis.

To quantitatively assess the likely impact, the state would need to develop the following:

- An established expected capacity price impact associated with the MOPR;
- An established methodology and a set of assumptions for estimating the pre-and post-MOPR capacity-based revenue for different types of clean energy technologies;
- An expected carbon price value applicable to generators in Illinois (and potentially to power imported from other states); and
- An expected PJM Commonwealth Edison Zone wholesale energy price impact due to the expected carbon price, which would likely need to be established through power flow modeling or another market simulation tool capable of estimating market prices.

4.6.2. Retail Customer Impact

Similar to clean energy project developers, it is possible that retail customers could face a net impact of zero from the MOPR and implementation of a carbon price. In this case of retail customers, this would happen if capacity market prices declined after the implementation of the MOPR and energy market prices increased due to the price on carbon emissions, as both market prices are factored into the retail prices. Yet, given that the MOPR effectively establishes a price floor for capacity market bids from a subset of generators that used to bid very low, this outcome seems unlikely.

Assuming that wholesale supply costs are passed through straight to retail consumers' bills by either their electric utility (e.g., Commonwealth Edison) or a competitive supplier, both capacity market price changes due to MOPR and energy market price changes due to carbon pricing would be passed through directly to retail customers. With respect to energy market prices, this is straightforward: a $3 per MWh increase in wholesale energy market prices would result in a $3 per MWh average retail price increase, all else equal. Changes in wholesale capacity market prices would be similarly passed through to retail customers.

In this situation, if capacity market prices decrease and energy market prices increase by similar amounts (in dollar per MWh terms), the impact of implementing MOPR and a carbon price could offset from the perspective of retail customers. However, the combination of the MOPR and carbon pricing could potentially result in a net increase in retail customers' bills. If the MOPR instead results in no change or an increase in capacity market prices in combination with an expected increase in energy market prices associated with a carbon price, then retail customers would experience a net increase in prices.

It is noteworthy that PJM's Independent Market Monitor (IMM) issued a report concluding that the MOPR "is not expected to have an impact on the clearing prices and auction revenues in the 2022/2023 [capacity market auction]." (Monitoring Analytics 2020) In addition, the IMM report noted, but rejected, estimates provided by FERC Commissioner (now Chairman) Glick and by consultancy Grid Strategies that the MOPR would increase costs to PJM customers. (Monitoring Analytics 2020) Thus, independent estimates of the net impact of the MOPR discussed in the IMM report range from neutral to an increase in cost to customers across the PJM market.

If the PJM IMM's conclusion proves correct and the MOPR has no impact on PJM capacity prices, then the adoption of a carbon price is very likely to drive an increase in retail electricity prices. In this case, the net effect of the MOPR and carbon pricing is for retail electricity prices to increase by the same amount that wholesale electricity prices increase due to Illinois' carbon price. As discussed above, if a carbon price causes a $3 per MWh increase in wholesale prices, this will likely be passed through to retail customers as an equivalent increase by their electricity supply company.

Based on the foregoing discussion, it is likely that implementing a carbon price in Illinois would result in some increase in retail customers' bills. However, to quantitatively assess the likely impact, the state would need the following:

- An established expected capacity price impact associated with the MOPR;
- An expected carbon price value applicable to generators in Illinois (and potentially to power imported from other states);
- An expected PJM Commonwealth Edison Zone wholesale energy price impact due to the expected carbon price, which would likely need to be established through power flow modeling or another market simulation tool capable of estimating market prices; and
- Illustrative or actual retail customer billing data and retail pricing structure assumptions in order to calculate the impact of these wholesale market impacts on retail customer bills.

5. SUMMARY OF RECOMMENDATIONS

A carbon pricing mechanism could help Illinois achieve carbon emission reductions, as evidenced by PJM's modeling data. In addition, it is possible that a carbon price would offer support to clean energy generators by increasing wholesale energy prices, although this benefit could also increase costs for retail consumers. Ultimately, these outcomes depend in part on PJM electricity market conditions and policies and in part on the state's decisions when implementing a carbon pricing mechansim.

This report synthesizes a large amount of existing information regarding the development, implementation, and potential market impacts of a carbon pricing mechansim. It also offers perspective on what this information means to the State of Illinois. However, further analysis specific to the State of Illinois' market context, goals, and stakeholders is necessary to refine the expected impacts and develop successful implementation plans. Therefore, this report also provides recommendations for future steps that the state should consider in evaluating potenial carbon pricing mechanisms.

RGGI provides one potential avenue for implementing a carbon pricing mechanism in Illinois. This approach offers relative administrative simplicity in that it is an established program and could allow PJM to incorporate a carbon price into its markets across a multi-state subregion. It also offers a number of states from which Illinois can learn from in implementing its carbon pricing mechanism.

In particular, the case studies presented in this report highlight that:

- Current RGGI member states use RGGI allowance revenues for purposes that are central to their overall goals;
- The activities funded by emission allowance revenues include energy efficiency measures and renewable energy deployment, as well as offsetting retail customer electricity costs;
- These states have also adopted a range of complementary energy policies, so their efforts to reduce emissions and increase clean energy deployment extend beyond their RGGI participation alone;
- Cap-and-trade programs in California and the European Union also use program revenues for important complementary purposes and have implemented additional emission reduction policies beyond the cap-and-trade programs;
- When considering its own adoption and implementation of a carbon pricing mechanism, Illinois should similarly consider how to best use allowance revenue to achieve its goals.

It is also, of course, critical for the State of Illinois to assess its implementation options in the context of the expected impact of its carbon pricing mechansim on markets and stakeholders. PJM's carbon pricing study provides a valuable glimpse at the potential near-term impact of a cap-and-trade program on Illinois as well as the rest of the RTO. However, there are several limitations to the model and the results published for the scenario including Illinois in the PJM carbon price subregion. Prior to advancing a concrete proposal for implementing carbon pricing in Illinois, the state should consider conducting or contracting with a third party to conduct its own market modeling to validate and extend PJM's results. Alternatively, the state could work with PJM to refine and expand this analysis. Issues that the state should address in its review of the existing data and future analysis include the following:

- The model only provides a single snapshot of the year 2023, which limits its utility in gauging long-term effects;
- The model results do not specify changes in demand, energy efficiency, cross border flows (imports/exports), and offgrid solar, resulting in an incomplete picture of the full range of changes that will occur to the electricity sector; and
- PJM does not provide the exact assumptions used for generators in the market and it may be of added benefit to adjust assumptions to generators in Illinois.

In addition to establishing expected wholesale electricity market impacts, the State of Illinois should also assess impacts on key stakeholders, particularly clean energy generators and retail customers. While these two groups clearly have different interests and face different impacts due to market changes, both would likely experience impacts associated with any carbon pricing mechanism that meaningfully impacts electricity markets. Both also face potential impacts associated with PJM's MOPR. To develop a detailed quantitative assessment of the likely impact of a carbon pricing mechanism on clean energy generators and retail consumers, the state would, at a minimum, likely need to develop the following:

- An established expected capacity price impact associated with the MOPR;
- An established methodology and set of assumptions for estimating the pre- and post-MOPR capacity-based revenue for different types of clean energy technologies;
- An expected carbon price value applicable to generators in Illinois (and potentially to power imported from other states); and
- An expected PJM Commonwealth Edison Zone wholesale energy price impact due to the expected carbon price, which would likely need to be established through power flow modeling or another market simulation tool capable of estimating market prices; and
- Illustrative or actual retail customer billing data and retail pricing structure assumptions in order to calculate the impact of these wholesale market impacts on retail customer bills.

Finally, this report is limited in scope to detailed discussion of 1) the PJM RTO, omitting detailed discussion of MISO, 2) cap-and-trade carbon pricing programs rather than a carbon tax mechanism, and

3) carbon pricing focused primarily or exclusively on the electricity sector rather than the majority of Illinois' economy. The state should, therefore consider extending any detailed analysis to the MISO market in the future and consider analyzing whether there might be advantages to carbon pricing mechanisms other than those addressed in this report.

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